AZURE MIDSTREAM PARTNERS, LP
Form 10-K
March 30, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark one)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
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

AZURE MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

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

(972) 674-5200
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units representing limited partner interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes No

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

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 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 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.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the Partnership's common units representing limited partner interests held by non-affiliates of the registrant was approximately $131,710,000 on June 30, 2015, based on the closing price as reported on New York Stock Exchange.

As of March 30, 2016, the registrant had 13,064,218 common units and 8,724,545 subordinated units outstanding.

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AZURE MIDSTREAM PARTNERS, LP

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For the Year Ended December 31, 2015

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GLOSSARY OF TERMS

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

Bbls: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbls/d: Stock tank barrel per day.

Bbls/hr: Stock tank barrel per hour.

Condensate: A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Crude oil: A mixture of hydrocarbons that exists in liquid phase in underground reservoirs.

Dry gas: A natural gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

End-user markets: The ultimate users and consumers of transported energy products.

EUR: Estimated ultimate recovery.

GPM: Gallons per Mcf.

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.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this 2015 Annual Report on Form 10-K (“Annual 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 simila 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 volatility of natural gas, crude oil and NGL prices and the price and demand of products derived from these commodities, particularly in the current depressed energy price environment, which has the potential for further deterioration and has resulted in a material reduction in oil and gas exploration, development and production;
- the volume of natural gas we gather and process and the volume of NGLs we transport;
- the volume of crude oil that we transload;
- the level of production of crude oil and natural gas and the resultant market prices of crude oil, natural gas and NGLs;
- the level of competition from other midstream natural gas companies and crude oil logistics companies in our geographic markets and industry;
- the level of our operating expenses;
- regulatory action affecting the supply of, or demand for, crude oil and natural gas, the transportation rates we can charge on our pipelines, how we contract for services, our existing contracts, our operating costs and our operating flexibility;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation;

- capacity charges and volumetric fees that we pay for NGL fractionation services;

- realized pricing impacts on our revenues and expenses that are directly subject to commodity price exposure;

- the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or non-performance by one or more of these parties;

- damage to pipelines, facilities, plants, related equipment and surrounding properties, including damage to third-party pipelines or facilities upon which we rely for transportation services, caused by hurricanes, earthquakes, floods, fires, severe weather, casualty losses, explosions and other natural disasters and acts of terrorism;

- outages at the processing or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;

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- actions taken by third-party operators, processors and transporters;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise;
- the level and timing of our expansion capital expenditures and our maintenance capital expenditures;
- the cost of acquisitions, if any;
- the level of our general and administrative expenses, including reimbursements to our General Partner and its affiliates for services provided to us;
- our level of indebtedness, debt service requirements, liquidity, compliance with our debt covenants and our ability to continue as a going concern;
- 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.

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.

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PART I

Items 1 and 2. Business and Properties

GENERAL OVERVIEW

In this Annual Report, the terms “Partnership”, “our”, “we”, “us” and “its” refer to Azure Midstream Partners, LP itself or Azu Midstream Partners, LP together with its consolidated subsidiaries, which includes the Azure System, as defined below, for all periods subsequent to November 14, 2013. On May 19, 2015, the Partnership changed its name from Marlin Midstream Partners, LP to Azure Midstream Partners, LP.

In this Annual Report the term “Azure System Predecessor” refers to the Legacy gathering system entities and assets (the "”Legacy System”), which has been deemed to be the predecessor of the Partnership for accounting and financial reporting purposes. The closing of the transactions described under "”Acquisition of the Legacy System"” (the “Transactions”) occurred on February 27, 2015, and was reflected in the consolidated financial statements of the Partnership using, for accounting purposes, a date of convenience of February 28, 2015 (the “Transaction Date”). The effect of recording the Transactions as of the Transaction Date was not material to the information presented.

In this Annual Report the term “Azure System” refers to the operations of the Legacy System, together with the contribution of Azure ETG, LLC; a Delaware limited liability company (“Azure ETG”) that owns and operates the East Texas gathering system, (the “ETG System”), for periods beginning November 15, 2013, representing the period Azure Midstream Energy LLC, a Delaware limited liability company (“Azure”), acquired 100% of the equity interests in the entities that own the Legacy System and the ETG System up to the Transaction Date. Azure contributed the ETG System to the Partnership on August 6, 2015, effective as of July 1, 2015. This transaction was determined to be a transaction between entities under common control for financial reporting purposes. Accordingly, we have recast the financial results of the Partnership to include the financial results of the ETG System for periods beginning November 15, 2013, the date Azure acquired the ETG System.

Organization and Description of Business

Azure Midstream Partners, LP is a Delaware limited 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”), Marlin Midstream, LLC (“Marlin Midstream”) and Azure ETG, we generate revenues by charging fees for gathering, transporting, treating and processing natural gas, transloading crude oil and selling or delivering NGLs to third parties.

In July 2013, we completed our initial public offering (“IPO”) of 6,875,000 common units 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. NuDevco is wholly owned by W. Keith Maxwell III, a former member of our board of directors, until February 2016, and former Chairman of the Board and Chief Executive Officer, until February 2015. Following the IPO, NuDevco owned and controlled Azure Midstream Partners GP, LLC, formerly Marlin Midstream GP, LLC (the “General Partner”).

Recent Developments

Going Concern Uncertainty

The Partnership’s liquidity outlook has changed throughout 2015 due to continued low commodity prices, which are expected to affect a number of companies in the oil industry, including our customers. Lower commodity

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prices have caused a significant reduction in drilling, completing and connecting new wells, which has caused a reduction in our forecasted volumes. These lower volumes have negatively impacted our operating cash flows. The downturn in the market has also effected the Partnership's ability to access the capital markets, which would have allowed the Partnership to facilitate growth or reduce debt.

As a result of these and other factors the Partnership's ability to comply with financial covenants and ratios in its senior secured revolving credit facility (the "Credit Agreement") has adversely impacted the Partnership's ability to continue as a going concern. Absent a waiver or amendment, failure to meet these covenants and ratios would have resulted in a default and, to the extent the applicable lenders so elect, an acceleration of the existing indebtedness, causing such debt of approximately $231.7 million to be immediately due and payable. Based upon our current estimates and expectations for commodity prices in 2016, we do not expect to remain in compliance with all of the restrictive covenants contained in its Credit Agreement throughout 2016 unless those requirements are waived or amended. The Partnership does not currently have adequate liquidity to repay all of its outstanding debt in full if such debt were accelerated.

The report of the Partnership's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report contains an explanatory paragraph regarding the substantial doubt about the Partnership's ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty. The Partnership's Credit Agreement contains the requirement to deliver audited consolidated financial statements without a going concern or like qualification or exception. Consequently, as of the filing date, March 30, 2016, the Partnership would have been in default under the Credit Agreement. Had we been unable to obtain a waiver or other suitable relief from the lenders under the Credit Agreement prior to the expiration of the 30 day grace period, an Event of Default (as defined in the Credit Agreement) would result in the lenders holding a majority of the commitments under the Credit Agreement, accelerate the outstanding indebtedness, which would make it immediately due and payable. On March 29, 2016, the Partnership entered into the Third Amendment (as defined below).

Our General Partners' board of directors and management are in the process of evaluating strategic alternatives to help provide the Partnership with financial stability, but no assurance can be given as to the outcome or timing of this process. The Partnership is currently in discussions with various stakeholders and is pursuing or considering a number of actions including: (i) obtaining additional sources of capital from asset sales, private issuances of equity or equity-linked securities, debt for equity swaps, or any combination thereof; (ii) obtaining waivers or amendments from its lenders; and (iii) continuing to minimize its capital expenditures, reduce costs and maximize cash flows from operations. There can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed.

Associated Energy Services, LP ("AES") Contract Terminations

During the first quarter of 2016, AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. The contracts have provisions requiring AES to make payments based on minimum volume commitments ("MVCs"). AES caused its bank to issue a $15.0 million letter of credit to the administrative agent under the Credit Agreement to secure the amount of its obligations under its logistics contracts. The Partnership's General Partner has approved a settlement agreement with AES and its parent, NuDevco, to resolve these issues under the gathering and processing agreements and the logistics contracts. Principal terms of the settlement include: (i) AES cooperation in the administrative agent's drawing down the full $15.0 million amount of the letter of credit, allowing proceeds from the draw to be applied to pay down debt under our Credit Agreement; (ii) the gathering and processing agreement and the logistics contracts are terminated effective as of January 1, 2016; (iii) NuDevco surrenders to the Partnership the 8,724,545 subordinated units, 1,939,265 common units and 10 IDR Units of the Partnership held by NuDevco or its subsidiary; (iv) the parties release each other from other claims in respect of the terminated contracts; and (v) AES will assign all of its rights and interests in third party contracts to Azure. The settlement agreement is subject to final approval from the lenders under the Credit Agreement.

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The AES gathering and processing contracts represented revenues of $29.1 million for the year ended December 31, 2015. These amounts represented 100% of the revenues for our logistics business segment for the year ended December 31, 2015.

W. Keith Maxwell III resigned from the board of directors effective February 19, 2016. Mr. Maxwell is the principal executive officer of NuDevco, which was one of the Partnership’s largest individual holders of common units and held all of the Partnership’s subordinated units. Mr. Maxwell is also the principal executive officer of AES, one of the Partnership’s largest customers for gathering and processing revenues, and the single customer for the logistics business.

As a result of the AES contract terminations, intangible assets of approximately $60.0 million associated with the terminated contracts will be eliminated in the first quarter of 2016.

Amendment to Credit Agreement

On March 29, 2016, the Partnership entered into the third amendment to the Credit Agreement (“Third Amendment”). The Third Amendment waived the affirmative covenant that stated if the Partnership’s annual financial statements, prepared in accordance with generally accepted accounting standards, contained any going concern qualification an event of default would result, for the year ended December 31, 2015. Additionally, the Third Amendment waived certain other events of default until June 30, 2016.

Under the terms of the Third Amendment, we are still prohibited from declaring or paying any distributions to unitholders if a default or event of default exists.

Suspension of Distribution

On February 1, 2016, the Partnership announced a temporary suspension of the distribution for the quarterly period ended December 31, 2015 as a result of covenant restrictions contained in our Credit Agreement. Our General Partners’ board of directors and management believe the suspension to be in the best long-term interest of all stakeholders. The board of directors will continue to evaluate the Partnership’s ability to reinstate the distribution, although reinstatement of distributions is not expected in the near term absent substantial improvement in our operating performance and compliance with the terms of our Credit Agreement.

Acquisition of the Legacy System

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

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

· we amended and restated our Agreement of Limited Partnership of Marlin Midstream Partners, LP (the "Partnership Agreement") to reflect the unitization of all of our incentive distribution rights (as unitized, the “IDR Units”) and recapitalized the incentive distribution rights owned by IDRH into 100 IDR Units;

· we redeemed 90 IDR Units held by IDRH in exchange for a payment by us of $63.0 million to IDRH (the “Redemption”);

· we acquired the Legacy System from Azure through the contribution, indirectly or directly, of: (i) all of the outstanding general and limited partner interests in Talco Midstream Assets, Ltd., a Texas limited liability company and subsidiary of Azure; and (ii) certain assets owned by TGG Pipeline, Ltd., a Texas limited

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liability company and subsidiary of Azure ("TGG"), in exchange for aggregate consideration of $162.5 million, which was paid to Azure in the form of $99.5 million in cash and by the issuance of 90 IDR Units, (the foregoing transaction, collectively, the “Contribution”); and

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

Following the consummation of the Transactions, Azure controlled us through its ownership of all of the equity interests in our General Partner. Our General Partner controlled us through its ownership of our outstanding general partner units, which represented a 1.96% economic general partner interest in us as of the Transaction Date. Azure also owns 90 IDR Units, which represented 90% of our IDR Units. NuDevco owned 10.8% of our common units and 100.0% of our subordinated units, representing 59.5% of our outstanding limited partner interests as of the Transaction Date and 10 IDR Units, which represented 10% of our IDR Units. See “Recent Developments – Associated Energy Services, LP (“AES”) Contract Terminations” for information regarding our current ownership.

Contribution of the ETG System

On August 6, 2015, we entered into a contribution agreement, (the “Contribution Agreement”) with Azure, which is the sole member of the General Partner. Pursuant to the Contribution Agreement, Azure contributed 100% of the outstanding membership interests in the ETG System to the Partnership in exchange for the consideration described below, (the "Contribution"). The closing of the transactions contemplated by the Contribution Agreement occurred simultaneously with the execution of the Contribution Agreement. The Contribution Agreement contains customary representations and warranties, indemnification obligations and covenants by the parties, and provides that the Partnership’s acquisition of the ETG System was effective on July 1, 2015.

The following transactions took place pursuant to the Contribution Agreement:

· as consideration for the membership interests of the ETG System, we paid Azure $80.0 million in cash and issued 255,319 common units to Azure representing limited partner interests in the Partnership; and

· we entered into a gas gathering agreement with TGG, an indirect subsidiary of Azure.

At December 31, 2015, after giving effect to our June 2015 public offering of common units, common units issued to Azure in connection with the Contribution Agreement representing 1.2% of our limited partner interests and phantom shares vested under the Marlin Midstream Partners, LP 2013 Long-Term Incentive Plan ("LTIP"), public security holders represented 49.8% of our outstanding limited partner interests and NuDevco held 49.0% of our outstanding limited partner interests.

Azure

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

OUR ASSETS AND AREAS OF OPERATION

Overview

We are a fee-based 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 gathering and processing segment and the logistics segment.

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For additional information relating to revenues, profits and total assets by operating segment, please see Note 10 "Segment Information" to our consolidated financial statements included in this Annual Report.

Gathering and Processing Segment

As of December 31, 2015, our gathering and processing segment primarily consisted of the following assets: (i) two related natural gas processing plants located in Panola County, Texas; (ii) an idle natural gas processing plant located in Tyler County, Texas; (iii) two natural gas gathering systems connected to our Panola County processing plants; and (iv) two NGL transportation pipelines that connect our Panola County and Tyler County processing plants to third party NGL pipelines. Our primary midstream natural gas assets are located in long-lived oil and natural gas producing regions in East Texas. These assets gather and process NGL-rich natural gas streams associated with production primarily from the Cotton Valley Sands, Haynesville Shale, Austin Chalk and Eaglebine formations.

During 2015, we have completed the following transactions:

· acquisition of the Legacy System, the results of operations of which are included within our gathering and processing segment. The addition of the Legacy System provides us with access to producing acreage that is currently not directly accessible within Harrison, Panola and Rusk counties in Texas. For a more detailed description of the Legacy System, see "Legacy Gathering System" below.

· acquisition of the ETG System, the results of operations of which are included within our gathering and processing segment. The addition of the ETG System provides us with four interconnections with major interstate pipelines providing 1.75 Bcf per day of access to downstream markets and a total of 336,000 gross acres in the Haynesville Shale and Bossier Shale formations. For a more detailed description of the ETG System, see "East Texas Gathering System" below.

The following table sets forth information about our primary midstream natural gas assets as of the year ended December 31, 2015 including the Legacy System, which was acquired in February 2015, and the ETG System contributed in August 2015:

Midstream Natural Gas	System Type	County, State	Miles	Gas Compression (bhp)	Approximate Design Capacity (MMcf/d

					otherwise noted)
Panola 1	Processing	Panola, Texas	N/A	8,220	100
Panola 2	Processing	Panola, Texas	N/A	10,400	120
Total Panola			N/A	18,620	220
Tyler (1)	Processing	Tyler, Texas	N/A	4,640	80
Marlin Midstream, LLC	Natural Gas Gathering	Panola and Harrison Counties, Texas	80	6,300	200
Turkey Creek (Bbls/d)	NGL Pipelines	Panola and Tyler Counties, Texas	12	N/A	20,000
Legacy Gathering System (2)	Natural Gas Gathering	Panola, Harrison and Rusk Counties, Texas and Caddo Parish Louisiana	666	14,125	500
East Texas Gathering System (3)	Natural Gas Gathering/Processing	Shelby, Nacogdoches, San Augustine and Sabine Counties, Texas and DeSoto Parish Louisiana	255	N/A	1,750

(1) The Tyler processing facility includes one 40 MMcf/d cryogenic train and two 20 MMcf/d cryogenic trains that are currently idle.

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(2) The Legacy Gathering System was acquired on February 27, 2015 in connection with the closing of the Transactions, and is currently operational.
(3) The East Texas Gathering System was acquired effective July 1, 2015 in connection with the closing of the Contribution Agreement and is currently operational.

Panola County Processing Plants

Our Panola County processing plants, which we refer to as our Panola 1 and Panola 2 processing plants, are situated northeast of the town of Carthage in East Texas on approximately 35 acres, and are operated as a single integrated facility, with common inlet and outlet points. These plants process NGL-rich natural gas from the Haynesville Shale and Cotton Valley natural gas production areas, which are areas known for their long-lived reserves. These plants are natural gas treating and cryogenic processing plants that include residue gas compression, amine treating and dehydration equipment with current design capacity to process up to 220 MMcf/d of natural gas.

Our Panola County plants have the following characteristics:

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

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

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

Tyler County Gas Processing Plant

Our Tyler County processing facility is situated northeast of the town of Woodville, in East Texas, on approximately ten acres. During 2015, our Tyler processing facility experienced declining production due to adverse economic factors, primarily the decline in oil and natural gas prices resulting in decreased volumes at the facility. Consequently, this facility was idled in the fourth quarter of 2015. This facility is available to be put back in service once volume levels increase to an economically beneficial level.

When operational, this facility processes NGL-rich natural gas from the Austin Chalk and Eaglebine natural gas production formations, which are areas known for their long-lived reserves. This facility consists of natural gas treating and cryogenic processing plants that include residue gas compression, amine treating, and glycol dehydration equipment with a design capacity to process up to 80 MMcf/d of natural gas.

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

We do not own or operate any natural gas gathering systems associated with our Tyler County processing plant. When the plant is operational, NGLs produced by our Tyler County processing plant are stored in two 30,000 gallon

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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 at the Mont Belvieu trading hub.

Marlin Midstream, LLC Gathering System

Our Marlin Midstream, LLC gathering system is comprised of our Lake Murvaul natural gas gathering system and our Oak Hill Lateral.

Our Lake Murvaul natural gas gathering system is connected to our Panola County processing plants and gathers natural gas primarily from delivery points on our gathering systems and interconnecting pipelines in the area. NuDevco and its affiliates purchased, from CenterPoint Energy, the original Lake Murvaul gathering system, consisting solely of a 12-inch trunk line extending approximately 10 miles southwest from the site of our Panola County processing plants. 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 Pipeline, LP, Texas Eastern Transmission, LP, ETC Gas Company Ltd., Natural Gas Pipeline Company of America LLC and DCP Midstream Partners, LP. Producers generally bear the cost of connecting their wells to our system at delivery points on our gathering systems.

Our Oak Hill Lateral, which was placed in service in March 2013, is connected to our Panola County processing plant and gathers natural gas through a connection to a gathering system owned by Anadarko Petroleum Company (“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:

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a 4-inch diameter y-grade NGL pipeline with a total capacity of 10,000 Bbls/d, expandable to 15,000 Bbls/d extending approximately two miles from our Panola County processing plants to a pipeline owned by TEPPCO Partners, L.P. for redelivery at the Mont Belvieu, Texas trading hub; and

· a 6-inch diameter y-grade NGL pipeline with a total capacity of 10,000 Bbls/d extending approximately 11 miles from our Tyler County processing plants to an NGL pipeline owned by West Texas LPG Pipeline Limited Partnership for redelivery at the Mont Belvieu, Texas trading hub.

Legacy Gathering System

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

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East Texas Gathering System

The ETG System was contributed to us as part of the Contribution Agreement effective July 1, 2015. The ETG System is primarily located within San Augustine, Nacogdoches, Sabine, Panola and Shelby Counties in East Texas, as well as DeSoto Parish in Louisiana, and currently serves multiple formations including the Haynesville, Bossier and the liquids-rich James Lime formation. The ETG System serves approximately 336,000 gross dedicated acres. The ETG System has one owned treating plant, 5 MMcf/d of processing capacity and four interconnections with major interstate pipelines providing 1.75 Bcf per day of access to downstream markets. The ETG System's Fairway processing plant is designed to extract NGL content for liquids processing from natural gas averaging 3.2 GPM from the James Lime formation.

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 CO2 treating capacity of approximately 20 MMcf/d.

Logistics Segment

Our logistics segment consists of three crude oil transloading facilities: (i) our Wildcat facility located in Carbon County, Utah, where we currently operate two skid transloaders and four ladder transloaders; (ii) our Big Horn facility located in Big Horn County, Wyoming, where we currently operate two skid transloaders and two ladder transloaders; and (iii) our East New Mexico facility located in Sandoval County, New Mexico, where we currently operate two skid transloaders and two ladder transloaders. Our transloaders are used to unload crude oil from tanker trucks and load crude oil into railcars. Our facilities provide transloading services for production originating from well-established crude oil producing basins, such as the Uinta, San Juan and Powder River Basins, which we believe are currently underserved by our competitors. Our combined transloading capacity is 31,200 Bbls/d in normal operating conditions. For the year ended December 31, 2015, AES accounted for 100% of the revenues attributable to our logistics segment.

Per the terms of the settlement agreement with AES, all of our gathering and processing agreements and logistics contracts with AES will be terminated effective January 1, 2016. As a result intangible assets of approximately $60.0 million associated with the terminated contracts will be eliminated in the first quarter of 2016. The Partnership currently does not have other contracts supplying revenue under the logistics segment. The Partnership will continue to evaluate the prospects for third-party revenue generation at each location but may ultimately conclude that operations at one or all of the locations should be terminated. See Item 1 and 2, "Business and Properties - Recent Developments" for further discussion of the AES contract terminations.

Wildcat Facility

At our Wildcat facility, crude oil is delivered to our site by third-party tanker trucks. The crude oil is then transferred from the truck to a railcar using either a skid transloader or a ladder transloader. On July 31, 2013, we entered into fee-based transloading services agreements with AES at our Wildcat facility that provide for a fixed fee per barrel for transloading services, subject to a MVC of 7,600 Bbls/d with respect to one of our skid transloaders and 1,260 Bbls/d with respect to two of our ladder transloaders.

Big Horn Facility

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

East New Mexico Facility

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

Amendment to Transloading Service Agreements

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

Our Fee-Based Commercial Agreements

We generate revenues primarily under fee-based gathering and processing agreements. During 2015, a significant portion of our revenues were generated under contracts with MVCs and annual inflation adjustments. Under our gathering and processing agreement with AES, payments were based on a fixed fee per Mcf, subject to annual inflation adjustments for gathering, treating, compression and processing services and a per gallon fixed fee for NGL transportation services. The agreement provided for a MVC of 80 MMcf/d.

Our gathering and processing agreements with Anadarko provided for a fixed fee per Mcf charge, subject to a MVC. The more significant contract with the MVC expired on April 30, 2015, and as a result volumes decreased throughout 2015. The Partnership still maintains a smaller minimum revenue commitment (“MRC”) contract for 20 MMcf/d.

Azure ETG maintains individually significant MVCs and a MRC with customers. Under the MRC, our customer agrees to pay a minimum monetary amount over certain periods during the term of the MRC. The customer must make a deficiency payment to us at the end of the contract year if actual revenues are less than its MRC for that year.

The customer is entitled to utilize the deficiency payments to offset gathering fees in future periods to the extent that such customer's revenues in the following periods exceed its MRC for that period. This contract provision ranges for the entire duration of the gas gathering agreement, which is ten years. We record customer billings for obligations under the MRC, solely with respect to this natural gas gathering agreement, as deferred revenue when the customer has the right to utilize deficiency payments to offset gathering fees in subsequent periods. We recognize deferred revenue under this arrangement as revenue once all contingencies or potential performance obligations associated with the related revenues have either: (i) been satisfied through the gathering of future excess volumes of natural gas; or (ii) expired, or lapsed through the passage of time pursuant to the terms of the natural gas gathering agreement. Under the MVC's, our customers agree to supply a minimum volume over certain periods during the term of the MVC. The customer must make a deficiency payment to us at the end of the contract term or contract periods. The MRC has a term that expires on December 31, 2020, while the other individual MVCs have terms expiring between August 31, 2020 and October 31, 2021.

Our transloading business has historically been serviced under five-year fee-based agreements with AES at our Wildcat, East New Mexico and Big Horn facilities. Under these transloading agreements, AES was required to pay us a fixed fee per barrel. The Wildcat and Big Horn agreements provided for a MVC of 7,600 Bbls/d at each facility with respect to two of our skid transloaders and 1,260 Bbls/d with respect to three of our ladder transloaders. The East New Mexico agreement provided for a MVC of 5,000 Bbls per weekday for one skid transloader at the facility. These agreements have subsequently been terminated as a result of nonpayment by AES. See Item 1 and 2, "Business and Properties - Recent Developments" for further discussion of the AES contract terminations.

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

SPONSOR RELATIONSHIP

As of December 31, 2015, NuDevco, our original sponsor, and affiliates held 10,663,810 of our limited partner units, consisting of 1,939,265 common units and 8,724,545 subordinated units, representing 49.0% of the outstanding limited partner interests, the public held 10,850,070 common units, representing 49.8% of our outstanding limited partner interests and Azure held 255,319 common units, representing 1.2% of our outstanding limited partner interests.

Subsequent to the closing of the Transactions on February 27, 2015, Azure owns 100% of our General Partner and indirectly holds all 429,365 general partner units representing a 1.93% general partner interest, and 90 of our incentive distribution rights, representing 90% of our IDR Units. Additionally, Azure acquired an option to acquire up to 20% of each of our common and subordinated units held by NuDevco as of the execution date of the Transaction Agreement.

As of March 30, 2016, the public held 10,869,634 common units, representing 49.8% of our outstanding limited partner interests, NuDevco held 10,663,810 of our limited partner units, consisting of 1,939,265 common units and 8,724,545 subordinated units, representing 49.0% of the outstanding limited partner interests and Azure held 255,319 common units, representing 1.2% of our outstanding limited partner interests. In connection with the closing of the Transactions, we: (i) terminated our existing Omnibus Agreement dated July 31, 2013 among us, NuDevco Partners, NuDevco Partners Holdings, LLC, a Texas limited liability company, NuDevco and the General Partner; and (ii) entered into an omnibus agreement, (the “New Omnibus Agreement”), with the General Partner and Azure.

The New Omnibus Agreement, among other things, states that:

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

·

we are obligated to reimburse Azure and its affiliates for costs and expenses incurred by Azure and its affiliates in providing the Services on our behalf;

· the General Partner or Azure may at any time temporarily or permanently exclude any particular Service from the scope of the New Omnibus Agreement upon 90 days' notice;

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

· we will have a right of first offer on any proposed transfer of any assets owned by Azure or its subsidiaries.

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.

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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

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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.

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. Local distribution companies and marketers, if the local distribution company 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 Federal Energy Regulatory Commission (“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.

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. These products include ethane, propane, isobutene, normal butane and natural gasoline.

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.

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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.

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

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

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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 are 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 and Kinder Morgan. Customers on our Legacy System include BP, Devon Energy Corporation, Endeavor Energy Resources, L.P., Indigo Resources LLC, Sabine Oil & Gas LLC and Samson Resources Corporation, among others. Customers on our ETG System include EOG, Aethon Energy Operating LLC, Devon Energy Corporation, Crimson Exploration, Inc. and Goodrich Petroleum Corp. 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, 2015, we had two customers that each accounted for more than 10% of our revenues. Those customers were AES, which accounted for 36.1% of our revenues and BP, which accounted for 11.8% of our revenues. Although we may have gathering, processing or transportation agreements with these customers, these agreements have remaining terms ranging from one to five years. As these agreements expire or are terminated, 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. As a result of a nonpayment, in the first quarter of 2016, our contracts with AES have been terminated.

AES has historically been our sole customer with respect to our crude oil logistics business and we have derived all of our transloading revenues from AES. AES contracts represented 100% of the capacity at our Wildcat, Big Horn, and East New Mexico facilities. During the first quarter of 2016, AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. These contracts have subsequently been terminated. Consequently, we currently have no contracts providing revenue to our crude oil logistics business segment. See Item 1 and 2, “Business and Properties - Recent Developments” for further discussion of the AES contract terminations. As part of the Transactions, AES pledged $15.0 million as collateral in support of a letter of credit facility on behalf of the logistics business segment. We have the ability to access the letter of credit in the event of nonpayment or nonperformance by AES. As a result of this nonpayment, we have instructed the lenders to draw on the letter of credit which will result in a repayment of $15.0 million of debt under our Credit Agreement.

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COMPETITION

The natural gas gathering, transmission, treating and processing businesses are highly competitive, and we face strong competition in acquiring new natural gas supplies. Our competition in obtaining additional natural gas supplies include interstate and intrastate pipelines and other midstream companies that gather, treat, process and market natural gas in the vicinity of our facilities. The ability to secure the dedication of natural gas supplies is primarily based on the reputation, efficiency, flexibility and reliability of the processor and the pricing of services. When commodity prices are high, producers generally desire to retain the full benefits of such increased commodity prices. Accordingly, in a high NGL pricing environment, fee-based arrangements are preferred by most producers. Our ability to tailor processing agreements to meet the specific needs of our customers, our ability to offer lower-priced services due to our relatively lower capital investments as compared to the rest of the industry and higher recovery efficiencies and lower fuel consumption at our facilities factor positively in our ability to compete in the markets we serve. The primary competitors of our Panola plants are DCP Midstream Partners, LP, Enable Midstream Partners LP, Midcoast Energy Partners, L.P. and MarkWest Energy Partners, L.P. The primary competitors of our idled Tyler County processing facility are Energy Transfer 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 EnLink Midstream Partners, LP, 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 customer for our crude oil transloading services has been AES. During the first quarter of 2016, AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. These AES contracts have been terminated. As a result, the Partnership will be evaluating other transloading contracts with customers in the areas in which we operate. See Item 1 and 2, “Business and Properties - Recent Developments” for further discussion of the AES contract terminations.

SAFETY AND MAINTENANCE

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

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

The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain gas transmission pipelines. In September 2013, PHMSA published a final rulemaking consistent with the 2011 Pipeline Safety Act that increases the maximum administrative civil penalties for violation of the pipeline safety laws and regulations to $0.2 million per violation per day, with a maximum of $2.0 million for a related series of violations.

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

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

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

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

- the U.S. Environmental Protection Agency ("EPA") Chemical Accident Prevention provisions, also known as the Risk Management Plan requirements, which are designed to prevent the accidental release of toxic, reactive, flammable or explosive materials;

- the U.S. Occupational Safety and Health Administration Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive materials; and

- the Department of Homeland Security Chemical Facility Anti-Terrorism standards, which are designed to regulate the security of high-risk chemical facilities.

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

REGULATION OF OPERATIONS

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

Regulation of Natural Gas Gathering

Section 1(b) of the Natural Gas Act of 1938 (“NGA”) exempts natural gas gathering facilities from the jurisdiction of 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.

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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, sale and 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 $1.0 million per day per violation of the NGA, the NGPA or their implementing regulations. In addition, the Commodity Futures Trading Commission (“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 $1.0 million 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

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complex federal, state and local laws and regulations relating to the protection of the environment. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. These laws and regulations may restrict or impact our business activities in many ways, such as:

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

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of investigatory, remedial and corrective action obligations and the issuance of orders enjoining some or all of our operations in affected areas. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances, petroleum hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, petroleum hydrocarbons or other waste products into the environment.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in compliance with existing environmental laws and regulations. Nonetheless, Congress and the federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, transportation, disposal, pollution control or cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. Moreover, accidental releases or spills may occur in the course of our operations, and we may incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We may not be able to recover all or any of these costs from insurance.

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

Hazardous Substances and Wastes

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, non-hazardous and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of such wastes or hydrocarbons. For instance, the

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

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

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

Air Emissions

Our operations are subject to the federal Clean Air Act ("CAA") and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, processing plants and transloading and storage facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions under either or both federal or state law. On October 1, 2015, the EPA published a final rule, effective December 28, 2015, revising the National Ambient Air Quality Standard for ozone to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards from 75 ppb. Further reduction, by the EPA, in the ozone standard, may require states to implement new more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely affect our business as well as the business of similarly situated companies in the industry.

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Water Discharges and Oil Releases

The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations

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

Hydraulic Fracturing

Some of our customers’ oil and gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. The process is typically regulated by state oil and gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including; (i) standards for the capture of air emissions released during hydraulic fracturing; (ii) proposed in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and (iii) issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management (“BLM”) issued a final rule, in March of 2015, which addressed fundamental standards for well integrity, water production and disclosure of chemicals used, to the BLM, for hydraulic fracturing activities. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states, including Texas, where we conduct operations and our customers conduct hydraulic fracturing, have adopted and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While we do not conduct hydraulic fracturing, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers' operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering, transportation and processing services, which could in turn adversely affect our revenues and results of operations.

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Endangered Species

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

Climate Change

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

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our or our oil and natural gas production customers' equipment and operations could require us or our customers to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or crude oil that we transport. For example, in November 2015, the EPA requested information related to hazardous air pollutant emissions from sources in the oil and natural gas production and natural gas transmission and storage segments of the oil and natural gas sector. The deadline to respond has been extended from January 2016 to March 2016. It is anticipated that the EPA will finalize, in 2016, new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of efforts to reduce methane emissions from the oil and gas sector.

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.

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Anti-terrorism Measures

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

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

EMPLOYEES

As of December 31, 2015, our General Partner and its affiliates had approximately 111 employees performing services for our operations. None of these employees are covered by collective bargaining agreements, and we believe that our General Partner and its affiliates have a satisfactory relationship with those employees.

In connection with the Transaction, we entered into the New Omnibus Agreement. Under the New Omnibus Agreement, Azure provides Services on behalf of the General Partner for our benefit. We are obligated to reimburse Azure and its affiliates for costs and expenses incurred by Azure and its affiliates in providing the Services on our behalf.

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

Item 1A. Risk Factors

RISK FACTORS

Risks Related to our Business

We have a significant amount of indebtedness, and there is substantial doubt about our ability to continue as a going concern.

As of December 31, 2015, we had an aggregate amount of approximately $231.7 million of debt outstanding. In 2015, we incurred a loss from operations of $222.4 million, including an impairment charge of $215.8 million. As of March 30, 2016, we had $14.4 million in cash and cash equivalents and no availability under our Credit Agreement. We are required, at the time of borrowing and as a condition to borrowing, to make certain representations to our lenders. We may not currently be able to make these representations, and we may not be able to do so in the future unless we can restructure our debt obligations or obtain additional financing. There can be no assurance that we will be able to restructure our debt obligations or obtain additional financing. While we will attempt to take appropriate mitigating actions to address our indebtedness prior to its maturity or to otherwise obtain additional financing, and to cure any potential defaults under the agreements governing such debt, there is no assurance that any particular action or actions

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with respect to refinancing existing indebtedness, obtaining additional financing or curing potential defaults in our debt agreements will be sufficient.

The consolidated financial statements included in this Annual Report have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful. If we are unable to repay or refinance our existing and future debt as it becomes due, whether at maturity or as a result of acceleration, we may be unable to continue as a going concern.

As of March 30, 2016, we had total indebtedness of $231.7 million. Based on our current debt balance, we expect to have interest payments due during 2016, totaling approximately $11.6 million. Our ability to make scheduled payments on, or to refinance, our debt obligations will depend on our financial and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. Lower commodity prices have negatively impacted our revenues, earnings and cash flows, and sustained low oil and natural gas prices will have a material and adverse effect on our liquidity position. We cannot assure you that our business will generate sufficient cash flows from operating activities or that future sources of capital will be available to us in an amount sufficient to permit us to service our indebtedness or repay our indebtedness as it becomes due or to fund our other liquidity needs. In addition, there can be no assurance that we will have the ability to borrow or otherwise raise the amounts necessary to repay or refinance our indebtedness as it matures. If we are unable to generate sufficient cash flow to service our debt or meet our debt obligations as they become due, we may be required to restructure or refinance all or a portion of our debt, obtain additional financing, sell some of our assets or operations or reduce or delay capital expenditures, including development efforts and acquisitions.

We may be unable to restructure or refinance our debt, obtain additional financing or capital or sell assets on satisfactory terms, if at all. If we cannot make scheduled payments on our debt, we will be in default under the terms of the agreements governing our debt and, as a result, our debt holders could declare all outstanding principal and interest to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. The lenders under our revolving credit facility could also terminate their commitments to lend us money and foreclose against the assets securing their borrowings and we could be forced into bankruptcy or liquidation. The uncertainty associated with our ability to meet our obligations as they become due raises substantial doubt about our ability to continue as a going concern. The report of the Partnership’s independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report contains an explanatory paragraph regarding the substantial doubt about the Partnership’s ability to continue as a going concern.

Based upon current estimates and expectations, we do not expect to remain in compliance with all of the financial covenants contained in the Credit Agreement throughout 2016. Our failure to obtain relief from this requirement under Credit Agreement could result in an acceleration of all of our outstanding debt obligations.

The downturn in the market has affected the Partnership's ability to access the capital markets, which, if successfully accessed, would have allowed the Partnership to reduce debt. As a result, the Partnership's ability to comply with financial covenants and ratios in the Credit Agreement has adversely impacted the Partnership's ability to continue as a going concern. Absent a waiver or amendment, failure to meet these covenants and ratios could result in the lenders accelerating the loans outstanding under the Credit Agreement. As a result of these factors, the audit report prepared by our auditors with respect to the financial statements in this Annual Report includes an explanatory paragraph expressing substantial doubt as to our ability to continue as a "going concern." As a result of the Partnership's inability to meet financial covenants for the first quarter of 2016 and the inclusion of the explanatory going concern paragraph in this Annual Report, absent the Third Amendment, we would have been in default under the Credit Agreement.

On March 29, 2016, the Partnership entered into the Third Amendment. Pursuant to the Third Amendment, we have received an agreement from our lenders to waive the affirmative covenant that stated if the Partnership's annual financial statements contained any going concern qualification an event of default would result, for the year ended December 31, 2015. Additionally, the Third Amendment waived certain other events of default until June 30, 2016. For additional information regarding the Third Amendment, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Credit Agreement.

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

The Credit Agreement limits our ability to, among other things: (i) incur additional debt; (ii) grant certain liens; (iii) make certain investments; (iv) engage in certain mergers or consolidations; (v) dispose of certain assets; (vi) enter into certain types of transactions with affiliates; (vii) make distributions, with certain exceptions, including the distribution of Available Cash, as defined in the Partnership Agreement, if no default or event of default exists and, during the Availability Period, as defined in the Credit Agreement, if an Availability deficiency exists, the aggregate amount of distributions of Available Cash made during such deficiency shall not exceed $10.0 million; (viii) enter into certain restrictive agreements or amend certain material agreements; and (ix) prepay certain debt.

As a result of the decline in commodity prices and associated decline in upstream oil and gas drilling activity, we experienced a decline in the growth in volume of natural gas we gather and process for our customers. These collective events impacted our operating results adversely and resulted in the need to amend our Credit Agreement. In October 2015, the Partnership entered into the second amendment to the Credit Agreement (the "Second Amendment") and the first amendment to the Security Agreement (the "Revised Security Agreement"). Among other things, the Partnership agreed to reduce the borrowing capacity under the Credit Agreement to $238.0 million in exchange for more favorable financial condition covenants, including amending our maximum permitted consolidated leverage ratio.

Under the terms of the Second Amendment, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default exists. In addition, under the Second Amendment, future distributions are contingent upon the maintenance of certain leverage ratios as detailed in the Second Amendment.

Given the lower commodity prices in 2015 and 2016, we would have exceeded the maximum permitted consolidated leverage ratio of 5.00 times consolidated adjusted EBITDA set forth in the Credit Agreement at the end of the first quarter of 2016, which required us to seek a waiver or amendment from our bank lenders. Further, there is a reasonable possibility that the Partnership will be unable to comply with the financial covenants over the next four quarters. The Third Amendment waived the affirmative covenant that stated if the Partnership's annual financial statements, prepared in accordance with generally accepted accounting standards, contained any going concern qualification an event of default would result, for the year ended December 31, 2015. Additionally, the Third Amendment waived certain other events of default until June 30, 2016.

As part of its balance sheet management, the Partnership is evaluating several alternatives to bolster its capital and liquidity position, including but not limited to asset sales and issuances of equity. The ability to comply with the financial covenants and to pay distributions will depend upon the Partnership's ability to reduce debt, increase its liquidity, or increase its Adjusted EBITDA due to a rebound in commodity prices and a related increase in drilling activity by the producers supplying its volumes. Please see "Management's Discussion and Analysis of Financial Condition-Liquidity and Capital Resources."

Accordingly, the provisions of our Credit Agreement may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our Credit Agreement could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

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Our level of indebtedness may reduce our financial flexibility.

As of December 31, 2015, the balance under our Credit Agreement was $231.7 million with commitments of up to $238.0 million.

Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;

- our increased vulnerability to competitive pressures or a downturn in our business or the economy generally; and

- our flexibility in responding to changing business and economic conditions may be limited.

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

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, AES and BP accounted for a substantial majority of our gross margin for the year ended December 31, 2015. These agreements have remaining terms ranging from two to five years. As these contracts expire, we will have to renegotiate extensions or renewals with these customers or replace the existing contracts with new arrangements with other customers. If any of these customers were to default on its contract or if we were unable to renew our contract with any 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.

During 2015, Anadarko cancelled a significant contract and as a result is no longer a significant customer. Further, in the first quarter of 2016 AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. These contracts were ultimately terminated. Consequently, AES is no longer a significant customer. See Item 1 and 2, "Business and Properties - Recent Developments" for further discussion of the AES contract terminations. BP and EOG are each expected to account for more than 10% of the gross margin of our combined businesses for the year ended December 31, 2016.

Historically, AES has been our sole customer with respect to our crude oil logistics business. As a result of the termination of our contracts with AES discussed in Item 1 and 2, "Business and Properties - Recent Developments" we currently have no customers for our crude oil logistics business. If we are unable to generate customers for this business, our business, results of operations, financial condition and ability to reinstate cash distributions to our unitholders would be materially and adversely affected.

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Historically, AES has been our sole customer with respect to our crude oil logistics business, and has represented the substantial majority of our transloading revenues in our crude oil logistics business. Contracts with AES represented 100% of the capacity at our Wildcat, Big Horn, and East New Mexico facilities and accounted for 17.3% of our revenues and $14.0 million of our gross margin for the year ended December 31, 2015. As a result of the termination of these contracts, we currently have no customers for our crude oil logistics business. If we are unable to generate customers for this business, our business, results of operations, financial condition and ability to reinstate cash distributions to our unitholders would be materially and adversely affected.

We may not generate sufficient distributable cash flow to resume the payment of quarterly distributions to holders of our common and subordinated units.

We have suspended cash distributions 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 $7.8 million per quarter, or $31.1 million per year, based on the number of common and subordinated units and the general partner interest outstanding as of December 31, 2015. We may not generate sufficient distributable cash flow each quarter to support the payment of the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

· our ability to contract successfully for throughput volumes of natural gas and crude oil;

· the volume of natural gas we gather and process and the volume of NGLs we transport;

· the volume of crude oil that we transload;

· the level of production of crude oil and natural gas and the resultant market prices of crude oil, natural gas and NGLs;

· the level of competition from other midstream natural gas companies and crude oil logistics companies in our geographic markets;

· the level of our operating expenses;

· regulatory action affecting the supply of, or demand for, crude oil or natural gas, the transportation rates we can charge on our pipelines, how we contract for services, our existing contracts, our operating costs or our operating flexibility;

- the effects of existing and future laws and governmental regulations;
- the effects of future litigation;
- capacity charges and volumetric fees that we pay for NGL fractionation services;
- realized pricing impacts on our revenues and expenses that are directly subject to commodity price exposure;
- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, casualty losses, explosions and other natural disasters and acts of terrorism including damage to third party pipelines or facilities upon which we rely for transportation services;
- outages at the processing or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;

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· actions taken by third-party operators, processors, and transporters; and

· leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise.

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

· the level and timing of our expansion capital expenditures and our maintenance capital expenditures;

· the cost of acquisitions, if any;

· the level of our general and administrative expenses, including reimbursements to our General Partner and its affiliates for services provided to us;

· our debt service requirements, liquidity, compliance without debt covenants and our ability to continue as a going concern 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.

On February 1, 2016, the Partnership announced a suspension of the distribution for the quarterly period ended December 31, 2015. The board of directors will continue to evaluate the Partnership's ability to reinstate the distribution, although reinstatement of distributions is not expected in the near term absent substantial improvement in our operating performance and compliance with the terms of our Credit Agreement.

Our commercial agreements subject us to renewal risks.

We currently gather, process and transport natural gas, and purchase, transport and sell NGLs, on our midstream natural gas systems under commercial agreements with terms of various durations. As our commercial agreements expire, we will have to negotiate extensions or renewals with our customers 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.

During 2015, the contracted MVCs of natural gas delivered by AES and Anadarko were below the committed amount at our Panola County processing facilities. Due to the decline in these volumes Anadarko may be unwilling to negotiate extensions or renewals of its commercial agreements with us on terms acceptable to us. As a result, Anadarko may make shortfall payments to us, from time to time, or none at all with respect to its MVCs. In addition, AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. Per the terms of the settlement agreement with AES, these contracts were subsequently terminated. 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.

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As discussed above and herein, Anadarko cancelled a significant contract and as a result is no longer a significant customer. The Partnership still maintains a smaller MRC contract for 20 MMcf/d. Further, in the first quarter of 2016, per the settlement agreement with AES, all contracts with AES will be terminated. Consequently, AES is no longer a significant customer. See Item 1 and 2, “Business and Properties - Recent Developments” for further discussion of the AES contract terminations.

We depend on a few key customers for a significant portion of our revenues. To the extent any one or more of these customers becomes financially distressed or commences bankruptcy proceedings, our revenues, cash flow and ability to make cash distributions to our unitholders could be materially adversely affected.

For the year ended December 31, 2015, 47.9% of our revenues were generated from two customers. Some of these customers may have material financial and liquidity issues or may be disproportionately affected as compared to larger, better-capitalized companies as a result of current economic and financial circumstances, operational incidents or other events. To the extent any one or more of these customers becomes financially distressed or commences bankruptcy proceedings, the contracts governing these customer relationships could be renegotiated at lower rates or rejected under applicable provisions of the United States Bankruptcy Code. Any such renegotiation or rejection could have a material adverse effect on our revenue and cash flows and our ability to make cash distributions to our unitholders.

Many of our assets have been in service for many years and require significant maintenance capital expenditures. As a result, our maintenance or repair costs may increase in the future.

Our pipelines, terminals and storage facilities are generally long-lived assets, and many of them have been in service for many years. The age and condition of our assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

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.

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

The natural gas volumes that support our midstream natural gas business are dependent on the level of production from crude oil and natural gas wells connected to our systems, the production of which will naturally decline over time. Likewise, the crude oil volumes that support our logistics business are dependent on the level of production from oil wells in our areas of operation. As a result, our cash flows associated with these wells will also decline over time unless we obtain new sources of natural gas and crude oil to maintain or increase throughput and transloading volumes. The primary factors affecting our ability to obtain non-dedicated sources of natural gas and crude oil include: (i) the level of successful drilling activity in our areas of operation; (ii) our ability to compete for volumes from successful new wells or from wells

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in which existing contractual arrangements with us and our competitors are expiring; and (iii) our ability to compete successfully for volumes from sources connected to other pipelines.

We have no 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, we have no control over producers or their drilling or production decisions, which are affected by, among other things:

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

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

- worldwide economic and political conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;

- the availability of imported liquefied natural gas, or LNG;
- the ability to export LNG;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials and premiums;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of crude oil, natural gas, LNG and other commodities.

Because of these factors, even if new natural gas or crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Further declines in natural gas prices could have a negative impact on exploration, development and production activity, and if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced

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utilization of our assets. If reductions in this activity result in our inability to maintain the current levels of natural gas throughput on our systems and the volumes of crude oil that we transload, it could reduce our revenues and cash flows and materially and adversely affect our ability to make cash distributions to our unitholders.

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

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

Distributions of available cash relating to surplus volumes in earlier periods may have the purpose or effect of: (i) enabling our General Partner or its affiliates to receive distributions on either subordinated units or IDR Units held by them; or (ii) 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. Our customers are not obligated to provide additional volumes to our gathering and processing systems or to our transloading facilities, and they may determine in the future that areas outside of our current areas of operation are strategically more attractive to them.

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

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

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

We operate in the midstream energy industry. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. In addition, decreases in demand may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, adverse weather conditions and government regulations affecting prices and production levels.

In recent years, the prices of crude oil and natural gas have been volatile, and we expect this volatility to continue. During the fourth quarter of 2015, crude oil prices based on WTI dropped sharply to a low of $42.16 per barrel, reflecting a decline from an average of $92.91 per barrel in 2014 and a high of $61.43 per barrel earlier in 2015. WTI crude oil prices averaged $31.78 per barrel in January 2016. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month futures contract ranged: in 2013, from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu; in 2014, from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu; and in 2015, from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu.

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

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

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

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

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

Our natural gas gathering, processing and transportation assets are dependent upon third-party pipelines and other facilities for natural gas supply and NGL takeaway capacity. Currently, our only direct NGL transportation option is Enterprise Products 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 and curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities becomes unable to receive or transport natural gas or NGLs, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and gross margin and our ability to make cash distributions to our unitholders could be materially and adversely affected.

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

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

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

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

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

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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.

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

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

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

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

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

We continuously consider and enter into discussions regarding potential acquisitions or growth capital expenditures. Any limitations on our access to new capital will impair our ability to execute this strategy. If the cost of capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. We may

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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. In addition, a variety of factors beyond our control could impact the availability of our cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the re-pricing of market risks and volatility in capital and financial markets.

Weak economic conditions and the volatility and disruption in the financial markets have increased the cost of raising money in the debt and equity markets while also diminishing the availability of funds from those markets. Weak economic conditions and competition for asset purchases have limited our ability to fully execute our growth strategy.

If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plans, enhance our existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

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

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

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

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

· mistaken assumptions about volumes, revenues and costs, including synergies and potential growth;

· an inability to secure adequate customer commitments to use the acquired systems or facilities;

· the risk that natural gas or crude oil reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;

· the assumption of unknown liabilities;

· coordinating geographically disparate organizations, systems and facilities;

· limitations on rights to indemnity from the seller;

· mistaken assumptions about the overall costs of equity or debt;

· the diversion of management's and employees' attention from other business concerns;

· unforeseen difficulties operating in new geographic areas and business lines; and

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· 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.

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

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

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

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

· damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;

· inadvertent damage from construction, vehicles, farm and utility equipment;

- leaks of natural gas and other petroleum hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;

- ruptures, fires and explosions; and

- other hazards that could also result in property and natural resource damage, personal injury and loss of life, pollution and suspension of operations.

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

- damage to transloading facilities, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;

- spills of crude oil and other hydrocarbons as a result of operator error or the malfunction of equipment or facilities;

- ruptures, fires and explosions; and

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· other hazards that could also result in property and natural resource damage, personal injury and loss of life, pollution and suspension of operations.

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

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

Our natural gas gathering operations are generally exempt from regulation by FERC, under the NGA, but FERC regulations still affect 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 be assured 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 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 Annual Report.

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

Pursuant to authority under the NGPSA and HLPSA, as amended by the Pipeline Safety Improvement Act of 2002, the PIPES Act, and the 2011 Pipeline Safety Act, PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for certain gas and hazardous liquid pipelines located where a leak or rupture could harm "high consequence areas," which are areas where a release could have the most significant adverse

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consequences, including high population areas, areas that are sources of drinking water, and unusually sensitive ecological areas.

These regulations require operators of covered pipelines, including us, to:

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

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. Texas, where we conduct our operations, has developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. We currently estimate an annual average cost of $0.3 million for the years 2016 and 2017 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

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

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

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing and verification of the maximum allowable pressure of certain pipelines.

In addition, PHMSA has issued Advisory Bulletins which, among other things, advise pipeline operators to review whether existing records of the operating parameters and conditions of their pipelines are able to provide adequate support for determining whether such pipelines are operating at a safe pressure. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing, could increase our costs or result in reductions of allowable operating pressures. The 2011 Pipeline Safety Act and implementing regulations also increase the maximum penalty for violation of pipeline safety regulations from $0.1 million to $0.2 million per violation

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per day of violation and also from $1.0 million to $2.0 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as other pipeline safety legislation or any implementation of PHMSA rules thereunder could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could and have a material adverse effect on our results of operations or financial position.

We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, compression, treating, processing and transportation operations, NGL transportation operations and transloading operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection.

These environmental laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations, or existing at our owned operation facilities. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenues.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to our handling of natural gas, NGLs, crude oil and other petroleum hydrocarbons, because of air emissions and product-related discharges arising out of our operations, and as a result of historical industry operations and waste disposal practices. Joint and several, strict liabilities may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of petroleum hydrocarbons or wastes on, under or from our facilities and pipelines, a few of which have been used for natural gas gathering, NGL transportation or crude oil transloading activities for a number of years. Private parties, including the owners of the properties through which our gathering or transportation systems pass or upon which our transloading facilities operate and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property and natural resource damages and fines or penalties for related violations of environmental laws or regulations. In addition, changes in environmental laws occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. For example, on October 1, 2014, the EPA published a final rule, effective December 28, 2015, revising the National Ambient Air Quality Standards for ozone to 70 ppb for both the 8-hour primary and secondary standards from 75ppb. We may not be able to recover all or any of these costs related to environmental laws and regulations 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 Annual Report.

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

We do not own all of the land on which our midstream natural gas pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if our pipelines are not properly located within the boundaries of such rights-of-way. Under the majority of our right-of-way contracts, we obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies until abandonment. However, certain of our right-of-way contracts are for a specified period of time. In addition, we do not own the sites on which our Wildcat, Big Horn and East New Mexico transloading facilities are located or where we conduct our transloading operations. We have a property lease at our Wildcat facility with a 12-year term expiring November 14, 2025, a property lease at our East New Mexico facility expiring April 30, 2017, and a rail siding lease at our Big Horn facility that is renewable annually on March 31.

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

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

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

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

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

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

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

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

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

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

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

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

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If we cannot meet the New York Stock Exchange's ("NYSE") "price criteria" continued listing standard, the NYSE may delist our common shares, which could have an adverse impact on the trading volume, liquidity and market price of our common shares.

If we do not maintain an average closing price of $1.00 or more for our common stock over any consecutive 30 trading-day period, the NYSE may delist our common shares for a failure to maintain compliance with the price criteria continued listing standard. As of March 29, 2016, the average closing price of our common shares over the immediately preceding consecutive 30 trading-day period was $1.67. The NYSE Listed Company Manual sets out rules and processes to cure non-compliance with this standard. For instance, upon approval from the NYSE, an issuer generally has six months to cure the listing standard related to stock price (such as a reverse-stock split), during which time the issuer's common stock would continue to be traded on the NYSE, subject to compliance with the other continued listing standards. A delisting of our common shares from the NYSE could negatively impact us because it could: (i) reduce the liquidity and market price of our common shares; (ii) reduce the number of investors willing to hold or acquire our common shares, which could negatively impact our ability to raise equity financing; (iii) limit our ability to use a registration statement to offer and sell freely tradable securities, thereby preventing us from accessing the public capital markets; and/or (iv) affect our ability to provide equity incentives to our employees.

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

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

Risks Inherent in an Investment in Us

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

Azure owns and controls our General Partner and will be responsible for the approval of all the officers and directors of our General Partners. Although our General Partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner that is beneficial to its owner. Conflicts of interest may arise between our General Partner and its affiliates, on the one hand, and us and our unitholders, on the other hand.

In resolving these conflicts of interest, our General Partner may favor its own interests and the interest of its affiliates over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

· neither our Partnership Agreement nor any other agreement requires our General Partner and its affiliates to pursue a business strategy that favors us;

· our General Partner is allowed to take into account the interests of parties other than us in resolving conflicts of interest;

· our Partnership Agreement limits the liability of and reduces the fiduciary duties owed by our General Partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval;

- our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;

- our General Partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our General Partner and the ability of the subordinated units to convert to common units;

- our General Partner determines which costs incurred by it are reimbursable by us;

- our General Partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the Subordination Period as defined in our Partnership Agreement;

- our Partnership Agreement permits us to classify up to $19.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our General Partner in respect of the general partner interest or to Azure and NuDevco in respect of the IDR Units;

- our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our General Partner intends to limit its liability regarding our contractual and other obligations;

- our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;

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

- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us; and

- our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our IDR Units without the approval of the conflicts committee of the board of directors of our General Partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

We currently list our common units on the NYSE under the symbol “AZUR.” Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our General Partner’s board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE’s shareholder approval rules that apply to a corporation. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. See Item 10. “Directors, Executive Officers and Corporate Governance,” for additional information.

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

Azure and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Azure or its affiliates may acquire, construct or dispose of additional midstream natural gas, crude oil logistics or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities, other than such obligations as set forth in the New Omnibus Agreement that we entered into with Azure and our General Partner at the closing of the Transactions. Moreover, except for the obligations set forth in the New Omnibus Agreement, neither Azure nor any of its affiliates has a contractual obligation to offer us the opportunity to purchase additional assets from it, and we are unable to predict whether or when such an offer may be presented and acted upon.

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

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

Our General Partner intends to limit its liability regarding our obligations.

Our General Partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our General Partner or its assets. Our General Partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our General Partner.

Our Partnership Agreement provides that any action taken by our General Partner to limit its liability is not a breach of our General Partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our General Partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

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

Although our Partnership Agreement requires we distribute all of our available cash, the distribution of available cash is dependent upon many factors such as, our discretionary operation and maintenance expense, general and administrative expense, capital expenditures, Credit Agreement capacity and availability, working capital levels, and the level of investments required to support our growth strategies. We have no obligation to make quarterly cash distributions in any amount and our General Partner has considerable discretion to determine the amount of our available cash each quarter.

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When available cash is approved by our General Partner for distribution 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, when available cash is approved by our General Partner for distribution to our unitholders, 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:

(i) 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;

(ii) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates;

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

(iv) 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 (iii) and (iv) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Azure, as the owner of the majority of our IDR Units, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related the IDR Units without the approval of the conflicts committee of the board of directors of our General Partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

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

We anticipate that Azure would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that Azure could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when Azure expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, Azure may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be

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issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for Azure to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to Azure in connection with resetting the target distribution levels related to the IDR Units.

Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. For example, unlike holders of stock in a public corporation, unitholders do not have “say-on-pay” advisory voting rights. Unitholders have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The board of directors of our General Partner will be chosen by Azure subsequent to the closing of the Transactions. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they have little ability to remove our General Partner. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders’ ability to influence the manner or direction of management.

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

The unitholders are currently unable to remove our General Partner without its consent. The vote of the holders of at least 66 $2/_3$% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. NuDevco indirectly owns 49.0% of our outstanding common and subordinated units. Pursuant to the Unitholder Agreement, dated as of February 27, 2015, by and among Azure, the General Partner, IDRH and NuDevco Midstream, NuDevco Midstream has agreed not to vote its common units in favor of the removal of the General Partner or in favor of any immediate successor general partner. Once the settlement agreement with AES is approved by the Partnership’s lenders under the Credit Agreement and becomes effective, NuDevco’s common and subordinated units will be surrendered to the Partnership and the Unitholder Agreement will be terminated.

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

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

Unitholders' voting rights are restricted by a provision of our Partnership Agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot vote on any matter.

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Our General Partner interest or the control of our General Partner may be transferred to a third party without unitholder consent.

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

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

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

The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

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

· the market price of the common units may decline.

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

· our business will no longer be solely managed by our General Partner's current owner, Azure;

· the newly admitted general partner may have sufficient ownership to be in a position to replace the board of directors and officers of our General Partner with its own nominees; and

· affiliates of the newly admitted general partner may compete with us, and neither our General Partner nor such affiliates will have any obligation to present business opportunities to us.

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

At December 31, 2015, we had 13,044,654 common units and 8,724,545 subordinated units outstanding and NuDevco holds an aggregate of 1,939,265 common units and 8,724,545 subordinated units. NuDevco continues to own the common units and subordinated units following the Transactions. All of the subordinated units will convert into common units at the end of the Subordination Period and may convert earlier under certain circumstances. The sale of

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these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

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

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our Partnership Agreement. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units. NuDevco indirectly owns approximately 14.8% 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 49.0% of our outstanding limited partner 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

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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 U.S. 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 U.S. 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 U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to our unitholders. Since a tax would be imposed upon us as a corporation, our distributable cash flow would be reduced substantially. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

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

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce distributable cash flow. Our Partnership Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Fiscal Year 2017 Budget proposed by the President recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2022. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration’s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the Internal Revenue Service, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. 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.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

In response to current market conditions, we may engage in transactions to deleverage the Partnership and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution.   For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, our unitholders may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on a unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

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

If a unitholder sells common units, such unitholder will recognize gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those units. Because distributions in excess of the unitholder's allocable share of our net taxable income decrease its tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units being sold will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price received is less than the unitholder's

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original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells units, such unitholder may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from the sale of units held by our unitholders, whether or not representing gain, may be taxed as ordinary income to our unitholders due to potential recapture items, including depreciation recapture. Thus, our unitholders may recognize both ordinary income and capital loss from the sale of their units if the amount realized on a sale of their units is less than their adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals under current law, up to $3,000 of ordinary income per year. In the taxable period in which our unitholder's sell their units, our unitholder's may recognize ordinary income from our allocations of income and gain to our unitholder's prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

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

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

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

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

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

We prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have previously adopted for our 2015 taxable year, and may not specifically authorize all aspects of our proration method thereafter. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

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

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

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

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As a result of investing in our common units, a unitholder may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

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

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PART II

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

MARKET INFORMATION

Our common units are listed on the NYSE under the symbol "AZUR." 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.

2015	First Quarter	Second Quarter	Third Quarter	Fourth Quarter (1)
High Price	$ 24.18	$ 23.89	$ 14.15	$ 10.15
Low Price	$ 16.50	$ 10.62	$ 5.29	$ 1.69
Distribution per common unit	$ 0.370	$ 0.370	$ 0.370	$ —

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
High Price	$ 18.66	$ 20.47	$ 21.80	$ 21.47
Low Price	$ 16.17	$ 17.10	$ 19.22	$ 16.53
Distribution per common unit	$ 0.355	$ 0.360	$ 0.365	$ 0.365

(1) On February 1, 2016, the Partnership announced a temporary suspension of the distribution for the quarterly period ended December 31, 2015.

As of March 30, 2016, there were approximately 5 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 429,365 general partner units for which there is no established public trading market. All general partner units are held by our General Partner.

OTHER SECURITIES MATTERS

Securities authorized for issuance under equity compensation plans.

In connection with the IPO, the board of directors of our General Partner adopted the LTIP. Individuals who are eligible to receive awards under the LTIP include: (i) our employees and the employees of NuDevco Midstream Development and its affiliates; (ii) directors of our General Partner; and (iii) consultants who perform services for us and our affiliates. The LTIP provides for the grant of unit options, unit appreciation awards, restricted units, phantom units, distribution equivalent rights, unit awards, profits interest units, and other unit-based awards. The maximum number of common units issuable under the LTIP is 1,750,000. As of December 31, 2015, 1,079,854 common units remained available for issuance under the LTIP.

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

For additional disclosures regarding securities authorized for issuance under equity compensation plans, see Part III, Item 12 “Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters”.

SELECTED INFORMATION FROM THE PARTNERSHIP AGREEMENT

Distributable cash and distributions.

The Partnership Agreement requires us to distribute all available cash to unitholders of record, as of the applicable record date, no later than 45 days after the end of each quarter.

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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;
- 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.

It is our intent to distribute our available cash to our unitholders, 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. On February 1, 2016, the Partnership announced a temporary suspension of the distributions for the quarterly period ended December 31, 2015. Should the distributions be reinstated, the common unitholders will be entitled to receive the minimum quarterly distribution of $0.35 per unit in arrears for each quarter as to which the distributions were suspended. Payment of any such amount in arrears will be subject to board of directors approval and compliance with the terms of our Partnership Agreement and the agreements governing our indebtedness.

The following distributions to our General Partner and limited partners were declared and paid for the period from January 1, 2014 to December 31, 2015:

Quarter ended:	Total Quarterly Distribution per Unit	Total Cash Distribution (1)	Date of Distribution
December 31, 2015 (2)	$ —	—	
September 30, 2015	$ 0.370	$ 8,213	November 13, 2015
June 30, 2015	$ 0.370	$ 8,187	August 14, 2015
March 31, 2015	$ 0.370	$ 6,763	May 15, 2015

December 31, 2014	$ 0.365	$ 6,593	February 11, 2015
September 30, 2014	$ 0.365	$ 6,593	November 4, 2014
June 30, 2014	$ 0.360	$ 6,469	August 5, 2014
March 31, 2014	$ 0.355	$ 6,375	May 6, 2014

(1) Total distribution amount includes the distribution paid to our General Partner and does not include the distribution equivalent rights payment that accrue on all unvested phantom units that have been issued under our LTIP.

(2) On February 1, 2016, the Partnership announced a temporary suspension of the distributions for the quarterly period ended December 31, 2015. See Note 4 “Partnership Equity and Distributions” to our consolidated financial statements included in this Annual Report.

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Performance Graph

The following performance graph compares the cumulative total unitholder return of our common units with the Standard & Poor's 500 Stock Index "S&P 500" and the Alerian MLP Total Return Index for the period from our IPO, July 26, 2013 to December 31, 2015, assuming an initial investment of $100.

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Item 6. Selected Financial Data

The following table presents the selected historical financial and operating data of the Partnership and the Azure System Predecessor for the periods presented. The selected historical financial data of the Partnership and Azure System Predecessor are derived from the historical financial statements of the Partnership and the Azure System Predecessor and should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this Annual Report. The following information is only a summary and is not necessarily indicative of the results of future operations of the Partnership and the Azure System Predecessor.

				Azure System Predecessor		
In thousands, except throughput	Year Ended December 31, 2015	Year Ended December 31, 2014	Period from November 15, 2013 to December 31, 2013 (1)	Period from January 1, 2013 to November 14, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011 (Unaudited)
Statement of Operations Data:						
Total operation revenues	$ 80,592	$ 74,721	$ 8,859	$ 41,263	$ 51,494	$ 68,393
Operating expenses:						
Cost of purchased gas and NGLs sold	18,408	38,042	4,505	21,054	22,793	37,447
Operating expense	20,776	13,714	2,643	11,330	11,183	17,787
General and administrative	14,183	5,812	195	3,629	5,692	5,845
Depreciation and amortization	20,957	7,961	958	9,999	11,229	17,093
Asset impairments	215,758	228	—	659	5,720	510
Total expenses	290,082	65,757	8,301	46,671	56,617	78,682
Income (loss) from operations	(209,490)	8,964	558	(5,408)	(5,123)	(10,289)
Interest expense (2)	11,333	15,149	1,855	3,167	4,951	2,852
Other (income) expense	916	422	—	(807)	304	4,001
Net loss before income taxes	(221,739)	(6,607)	(1,297)	(7,768)	(10,378)	(17,142)
Income tax expense	686	213	26	118	147	195
Net loss	$ (222,425)	$ (6,820)	$ (1,323)	$ (7,886)	$ (10,525)	$ (17,337)
Balance Sheet Data (as of the period end):						
Property plant and equipment, net	$ 485,155	$ 304,175	$ 302,163	$ 341,848	$ 336,620	$ 353,461
Total assets	$ 567,226	$ 319,203	$ 324,563	$ 351,102	$ 345,381	$ 365,913
Partners' capital and parent company net investment	$ 316,447	$ 116,151	$ 107,028	$ 218,531	$ 189,547	$ 212,187
Key Performance Measures:						
Adjusted EBITDA (3)	$ 40,255	$ 25,805	$ 2,702	$ 5,155	$ 11,826	$ 7,314
Capital expenditures (4)	$ 4,738	$ 14,233	$ 1,068	$ 13,989	$ 9,887	$ n/a

Operating Data:						
Average throughput volumes of natural gas (MMcf/d)	300	261	209	189	254	324

(1) Beginning November 15, 2013, Azure acquired 100% equity interest in the Azure System. On August 6, 2015, effective July 1, 2015, Azure contributed the ETG System to the Partnership. This transaction was determined to be a transaction between entities under common control for financial reporting purposes. As such, we have recast the financial results of the Azure System to include the financial results of the ETG System from the period November 15, 2013 to December 31, 2013 and the years ended December 31, 2014 and 2015.

(2) The interest expense reflected within the Azure System and Azure System Predecessor's statement of operations data represents an allocation of its proportionate share of the Azure and Azure Predecessor's consolidated interest expense in accordance with applicable accounting guidance.

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(3) For a definition of Adjusted EBITDA and a reconciliation to net income, its most directly comparable financial measure calculated in accordance with GAAP, please read "Non-GAAP Financial Measures" below.
(4) For the year ended December 31, 2011, capital expenditure data was not available due to system constraints.

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

In this Annual Report, the terms “Partnership”, “our”, “we”, “us” and “its” refer to Azure Midstream Partners, LP itself or Azu Midstream Partners, LP together with its consolidated subsidiaries, which includes the Azure System, as defined below, for all periods subsequent to November 14, 2013. On May 19, 2015, the Partnership changed its name from Marlin Midstream Partners, LP to Azure Midstream Partners, LP.

In this Annual Report the term “Azure System Predecessor” refers to the Legacy gathering system entities and assets (the "”Legacy System”), which has been deemed to be the predecessor of the Partnership for accounting and financial reporting purposes. The closing of the transactions described under "”Acquisition of the Legacy System"” (the “Transactions”) occurred on February 27, 2015, and was reflected in the consolidated financial statements of the Partnership using, for accounting purposes, a date of convenience of February 28, 2015 (the “Transaction Date”). The effect of recording the Transactions as of the Transaction Date was not material to the information presented.

In this Annual Report the term “Azure System” refers to the operations of the Legacy System, together with the contribution of Azure ETG, LLC; a Delaware limited liability company (“Azure ETG”) that owns and operates the East Texas gathering system, (the “ETG System”), for periods beginning November 15, 2013, representing the period Azure Midstream Energy LLC, a Delaware limited liability company (“Azure”), acquired 100% of the equity interests in the entities that own the Legacy System and the ETG System up to the Transaction Date. Azure contributed the ETG System to the Partnership on August 6, 2015, effective as of July 1, 2015. This transaction was determined to be a transaction between entities under common control for financial reporting purposes. Accordingly, we have recast the financial results of the Partnership to include the financial results of the ETG System for periods beginning November 15, 2013, the date Azure acquired the ETG System.

You should read this discussion and analysis of financial condition and results of operations in conjunction with the historical financial statements and accompanying notes included elsewhere in this Annual Report on Form 10-K (“Annual Report”).

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 gathering and processing business segment, and crude oil transloading services, which we refer to as our logistics business segment.

Recent Developments

Going Concern Uncertainty

The Partnership’s liquidity outlook has changed throughout 2015 due to continued low commodity prices, which are expected to affect a number of companies in the oil industry, including our customers. Lower commodity prices have caused a significant reduction in drilling, completing and connecting new wells, which has caused a reduction in our forecasted volumes. These lower volumes have negatively impacted our operating cash flows. The downturn in the market has also effected the Partnership’s ability to access the capital markets, which would have allowed the Partnership to facilitate growth or reduce debt.

As a result of these and other factors the Partnership’s ability to comply with financial covenants and ratios in its senior secured revolving credit facility (the "Credit Agreement") has adversely impacted the Partnership’s ability to continue as a going concern. Absent a waiver or amendment, failure to meet these covenants and ratios would have resulted in a default and, to the extent the applicable lenders so elect, an acceleration of the existing indebtedness,

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causing such debt of approximately $231.7 million to be immediately due and payable. Based upon our current estimates and expectations for commodity prices in 2016, we do not expect to remain in compliance with all of the restrictive covenants contained in its Credit Agreement throughout 2016 unless those requirements are waived or amended. The Partnership does not currently have adequate liquidity to repay all of its outstanding debt in full if such debt were accelerated.

The report of the Partnership's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report contains an explanatory paragraph regarding the substantial doubt about the Partnership's ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty. The Partnership's Credit Agreement contains the requirement to deliver audited consolidated financial statements without a going concern or like qualification or exception. Consequently, as of the filing date, March 30, 2016, the Partnership would have been in default under the Credit Agreement. Had we been unable to obtain a waiver or other suitable relief from the lenders under the Credit Agreement prior to the expiration of the 30 day grace period, an Event of Default (as defined in the Credit Agreement) would result in the lenders holding a majority of the commitments under the Credit Agreement, accelerate the outstanding indebtedness, which would make it immediately due and payable. On March 29, 2016, the Partnership entered into the Third Amendment (as defined below).

Our General Partners' board of directors and management are in the process of evaluating strategic alternatives to help provide the Partnership with financial stability, but no assurance can be given as to the outcome or timing of this process. The Partnership is currently in discussions with various stakeholders and is pursuing or considering a number of actions including: (i) obtaining additional sources of capital from asset sales, private issuances of equity or equity-linked securities, debt for equity swaps, or any combination thereof; (ii) obtaining waivers or amendments from its lenders; and (iii) continuing to minimize its capital expenditures, reduce costs and maximize cash flows from operations. There can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed.

Associated Energy Services, LP ("AES") Contract Terminations

During the first quarter of 2016, AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. The contracts have provisions requiring AES to make payments based on minimum volume commitments ("MVCs"). AES caused its bank to issue a $15.0 million letter of credit to the administrative agent under the Credit Agreement to secure the amount of its obligations under its logistics contracts. The Partnership's General Partner has approved a settlement agreement with AES and its parent, NuDevco, to resolve these issues under the gathering and processing agreements and the logistics contracts. Principal terms of the settlement include: (i) AES cooperation in the administrative agent's drawing down the full $15.0 million amount of the letter of credit, allowing proceeds from the draw to be applied to pay down debt under our Credit Agreement; (ii) the gathering and processing agreement and the logistics contracts are terminated effective as of January 1, 2016; (iii) NuDevco surrenders to the Partnership the 8,724,545 subordinated units, 1,939,265 common units and 10 IDR Units of the Partnership held by NuDevco or its subsidiary; (iv) the parties release each other from other claims in respect of the terminated contracts; and (v) AES will assign all of its rights and interests in third party contracts to Azure. The settlement agreement is subject to final approval from the lenders under the Credit Agreement.

The AES gathering and processing contracts represented revenues of $29.1 million for the year ended December 31, 2015. These amounts represented 100% of the revenues for our logistics business segment for the year ended December 31, 2015.

W. Keith Maxwell III resigned from the board of directors effective February 19, 2016. Mr. Maxwell is the principal executive officer of NuDevco, which was one of the Partnership’s largest individual holders of common units and held all of the Partnership’s subordinated units. Mr. Maxwell is also the principal executive officer of AES, one of the Partnership’s largest customers for gathering and processing revenues, and the single customer for the logistics business.

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As a result of the AES contract terminations, intangible assets of approximately $60.0 million associated with the terminated contracts will be eliminated in the first quarter of 2016.

Amendment to Credit Agreement

On March 29, 2016, the Partnership entered into the third amendment to the Credit Agreement ("Third Amendment"). The amendment waived the affirmative covenant that stated if the Partnership's annual financial statements, prepared in accordance with generally accepted accounting standards, contained any going concern qualification an event of default would result, for the year ended December 31, 2015. Additionally, the Third Amendment waived certain other events of default until June 30, 2016.

Under the terms of the Third Amendment, we are still prohibited from declaring or paying any distributions to unitholders if a default or event of default exists.

Suspension of Distribution

On February 1, 2016, the Partnership announced a temporary suspension of the distribution for the quarterly period ended December 31, 2015 as a result of covenant restrictions contained in our Credit Agreement. The Partnership's board of directors and management believe the suspension to be in the best long-term interest of all stakeholders. The board of directors will continue to evaluate the Partnership's ability to reinstate the distribution, although reinstatement of distributions is not expected in the near term absent substantial improvement in our operating performance and compliance with the terms of our Credit Agreement.

Acquisition of the Legacy System

On February 27, 2015, we completed the Transactions pursuant to a Transaction Agreement, dated January 14, 2015 (the "Transaction Agreement"), by and among us, Azure, Azure Midstream Partners GP, LLC, formerly Marlin Midstream GP, LLC, (the "General Partner"), NuDevco Partners, LLC and its affiliates ("NuDevco") and Marlin IDR Holdings, LLC, a Delaware limited liability company and wholly owned subsidiary of NuDevco ("IDRH"). The consummation of the Transaction Agreement resulted in Azure contributing the Legacy System to us, and Azure receiving $92.5 million in cash and acquiring 100% of the equity interests in our general partner and 90% of our incentive distribution rights.

The following transactions were consummated in connection with the closing of the Transactions:

- we (i) amended and restated our Agreement of Limited Partnership of Marlin Midstream Partners, LP (the "Partnership Agreement") to reflect the unitization of our incentive distribution rights (as unitized, the “IDR Units”); and (ii) recapitalized the incentive distribution rights owned by IDRH into 100 IDR Units;

- we redeemed 90 IDR Units held by IDRH in exchange for a payment of $63.0 million to IDRH (the “Redemption”);

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

- Azure purchased from NuDevco: (i) all of the outstanding membership interests in the general partner for $7.0 million; and (ii) an option to acquire up to 20% of our common and subordinated units held by NuDevco as of the execution date of the Transaction Agreement.

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Contribution of the ETG System

On August 6, 2015, we entered into a contribution agreement (the “Contribution Agreement”) with Azure, which is the sole member of the General Partner. Pursuant to the Contribution Agreement, Azure contributed 100% of the outstanding membership interests in Azure ETG to the Partnership in exchange for the consideration described below. The closing of the transactions contemplated by the Contribution Agreement occurred simultaneously with the execution of the Contribution Agreement. The Contribution Agreement contains customary representations and warranties, indemnification obligations and covenants by the parties, and provides that the Partnership’s acquisition of the ETG System was effective on July 1, 2015.

The following transactions took place pursuant to the Contribution Agreement:

- as consideration for the membership interests of Azure ETG, we paid Azure $80.0 million in cash and issued 255,319 common units representing limited partner interests in the Partnership to Azure; and

- we entered into a gas gathering agreement (the “Gas Gathering Agreement”) with TGG, an indirect subsidiary of Azure.

Listing of Our Common Units on the New York Stock Exchange

On May 20, 2015, we submitted written notice to NASDAQ Global Market to voluntarily delist our common units and applied to list our common units on the New York Stock Exchange ("NYSE"). The delisting became effective following the close of business on May 28, 2015, and our common units commenced trading on the NYSE at market open on May 29, 2015 under the ticker "AZUR".

Public Offering of Our Common Units

On June 17, 2015, we and the general partner entered into an Underwriting Agreement with Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC, as representatives of the several underwriters named therein, the (“Underwriting Agreement”), relating to the public offering of 3,500,000 common units representing limited partner interests in the Partnership at a price to the public of $14.17 per common unit, the (“Offering”). Pursuant to the Underwriting Agreement, we also granted the underwriters a 30-day option to purchase up to an additional 525,000 common units at the same price.

The Offering closed on June 22, 2015. We received net proceeds from the sale of the common units sold in the Offering of approximately $48.3 million, including the proportionate capital contribution by the general partner to maintain its 1.93% general partner interest and after deducting the underwriting discount and estimated offering expenses payable by the Partnership.

On July 17, 2015, the underwriters of the Offering exercised their option to purchase an additional 90,000 common units at a price to the public of $14.17 per common unit. Total net proceeds from the sale of these additional common units, including the general partner's proportionate capital contribution and after deducting underwriting discounts and commissions and estimated offering expenses, was $1.2 million.

Ownership

As of December 31, 2015, Azure owned and controlled: (i) the general partner, through its ownership of a 1.93% general partner interest in us; (ii) 90% of our IDR Units; and (iii) 255,319 of our common units representing a 1.2% limited partner interest. As of December 31, 2015, NuDevco owned: (i) 1,939,265 of our common units, representing a 8.9% limited partner interest; (ii) 8,724,545 of our subordinated units, representing a 40.1% limited partner interest; and (iii) 10% of our IDR Units. As of December 31, 2015, the public owned 10,850,070 of our common units, representing a 49.8% limited partner interest. Azure, through its ownership of our general partner, controls us and is responsible for managing our business and operations.

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As of March 30, 2016, the public held 10,869,634 common units, representing 49.8% of our outstanding limited partner interests, NuDevco held 10,663,810 of our limited partner units, consisting of 1,939,265 common units and 8,724,545 subordinated units, representing 49.0% of the outstanding limited partner interests and Azure held 255,319 common units, representing 1.2% of our outstanding limited partner interests

Basis of Presentation

The following financial information gives effect to the business combination and the Transactions and the transactions contemplated by the Contribution Agreement discussed above.

Under the acquisition method of accounting, the business combination was accounted for in accordance with the applicable reverse merger accounting guidance. Azure acquired a controlling financial interest in us through the acquisition of our General Partner. As a result, the Azure System Predecessor is deemed to be the accounting acquirer of the Partnership because its parent company, Azure, obtained control of the Partnership through its control of our General Partner. Consequently, the Azure System Predecessor is deemed to be the predecessor of the Partnership for financial reporting purposes, and the historical financial statements of the Partnership were recast to reflect the Azure System Predecessor for all periods prior to November 15, 2013, and the Azure System for all periods subsequent to November 15, 2013, the date Azure acquired the Legacy System and ETG System, up to the Transaction Date.

The Azure System and Azure System Predecessor's assets and liabilities retained their historical carrying values. Additionally, the Partnership's assets acquired and liabilities assumed by the Azure System Predecessor in the business combination were recorded at their fair values measured as of the Transaction Date. The excess of the assumed purchase price of the Partnership over the estimated fair values of the Partnership's net assets acquired were recorded as goodwill. The assumed purchase price or enterprise value of the Partnership was determined using acceptable fair value methods, and is partially derived from the consideration Azure paid for our General Partner and 90% of our IDR Units. Additionally, because the Azure System Predecessor is reflected at Azure’s historical cost, the difference between the $162.5 million in consideration paid by the Partnership and Azure's historical carrying values (net book value) at the Transaction Date was recorded as an increase to partners’ capital in the amount of $51.7 million. The purchase price and fair values were prepared with the assistance of our external fair value specialists and represent management's best estimate of the enterprise value and fair values of the Partnership.

The contribution of the ETG System by Azure to the Partnership on August 6, 2015, effective July 1, 2015, was determined to be a transaction between entities under common control for financial reporting purposes. Because the contribution of the ETG System is considered to be a transaction among entities under common control, the ETG System is reflected at Azure's historical cost and the difference between that historical cost and the purchase price is recorded as an adjustment to partners' capital. In addition, we have included in the financial results of the Partnership the financial results of the ETG System for all periods subsequent to November 15, 2013, the date Azure acquired the

ETG System.

OUR ASSETS

Our assets and operations are organized into the following two operating segments:

Gathering and Processing Segment

Our gathering and processing segment consists primary of midstream natural gas assets, including: (i) two related natural gas processing facilities located in Panola County, Texas with an approximate design capacity of 220 MMcf/d; (ii) an idle natural gas processing facility located in Tyler County, Texas with an approximate design capacity of 80 MMcf/d; (iii) high-and low-pressure gathering lines that currently serve approximately 100,000 dedicated acres and have access to seven major downstream markets, our Panola County processing plants and three third-party processing plants; 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.

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Our primary gathering and processing segment 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.

On August 6, 2015, effective July 1, 2015, we completed the contribution of the ETG system, the results of operations of which will be included within our gathering and processing segment. The ETG system is primarily located within San Augustine, Nacogdoches, Sabine, Panola and Shelby Counties in East Texas and currently serves multiple formations including the Haynesville, Bossier and the liquids-rich James Lime formation. The ETG system consists of approximately 255 miles of gathering lines and serves approximately 336,000 gross dedicated acres. The system has two owned treating plants, 5 MMcf/d of processing capacity and four interconnections with major interstate pipelines providing 1.75 Bcf per day of access to downstream markets. The ETG System's Fairway processing plant is designed to extract NGL content from natural gas averaging 3.2 GPM from the James Lime formation for liquids processing.

Logistics Segment

Our logistics segment consists of three crude oil transloading facilities: (i) our Wildcat facility located in Carbon County, Utah, where we currently operate two skid transloaders and four ladder transloaders; (ii) our Big Horn facility located in Big Horn County, Wyoming, where we currently operate two skid transloaders and two ladder transloaders; and (iii) our East New Mexico facility located in Sandoval County, New Mexico, where we currently operate two skid transloaders and two ladder transloaders. Our transloaders are used to unload crude oil from tanker trucks and load crude oil into railcars. Our facilities provide transloading services for production originating from well-established crude oil producing basins, such as the Uinta, San Juan and Powder River Basins, which we believe are currently underserved by our competitors. Our combined transloading capacity is 31,200 Bbls/d in normal operating conditions. For the year ended December 31, 2015, AES accounted for 100% of the revenues attributable to our logistics segment.

As a result of the AES contract terminations, the Partnership currently does not have other contracts supplying revenue under the logistics segment. The Partnership will continue to evaluate the prospects for third-party revenue generation at each location but may ultimately conclude that operations at one or all of the locations should be terminated.

FACTORS AFFECTING THE COMPARABILITY OF OUR OPERATING RESULTS

As described above, the Azure System Predecessor was deemed to be the accounting acquirer of the Partnership in accordance with applicable business combination accounting guidance and, as a result, the historical financial statements of the Partnership were recast to reflect the statement of position and results of operations of the Azure System Predecessor for periods prior to November 15, 2013, and the Azure System for all periods subsequent to November 15, 2013, the date Azure acquired the Legacy System and ETG System, up to the Transaction Date.

Therefore, the Partnership's future results of operations may not be comparable to the Azure System's historical results of operations for the reasons described below.

Ownership

Azure controls us through its ownership of our General Partner, and Azure is responsible for the management of the operations of our business. In connection with the closing of the Transactions, the Partnership terminated its omnibus agreement, dated July 31, 2013, (the "Original Omnibus Agreement"), by and between NuDevco, the General Partner and the Partnership. Also in connection with the closing of the Transactions, the Partnership entered into an omnibus agreement, (the "New Omnibus Agreement") with the General Partner and Azure, pursuant to which, among other things:

- Azure will provide corporate, general and administrative services (the "Services") on behalf of the General Partner for the benefit of the Partnership and its subsidiaries;
- the Partnership is obligated to reimburse Azure and its affiliates for costs and expenses incurred by Azure and its affiliates in providing the Services on behalf of the Partnership;

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

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

- the Partnership will have a right of first offer on any proposed transfer of any assets owned by Azure or its subsidiaries.

The Partnership's ongoing results of operations are comprised of our gathering and processing business segment, including the Azure System, and our logistics business segment. The ongoing results of operations are under Azure management, as it controls our General Partner. As a result, the historical results of operations of the Azure System will not be comparable to the Partnership's future results of operations.

Revenues

The revenues generated by the Partnership consist of the revenues from the gathering and processing segment, including the Azure System, and the logistics segment subsequent to the Transaction Date. The historical revenues included within the Partnership's financial statements prior to the Transaction Date are comprised of the Azure System. The Azure System’s primary revenue-producing activities are the sales of natural gas and NGLs and the sale of condensate liquids. The Azure System also earns gathering services and other fee-based revenues from the gathering, compression and treating of natural gas. The Partnership's revenues are primarily derived from natural gas processing and fees earned from its gathering, processing and transloading operations. Therefore, our ongoing operating results include incremental gathering, processing and other fee-based revenues compared with the historical revenues of the Azure System.

Operation and Maintenance

The operation and maintenance expenses incurred by the Partnership consist of the Azure System, and the logistics segment subsequent to the Transaction Date. The historical operation and maintenance expenses included within the Partnership’s financial statements prior to the Transaction Date are comprised of the Azure System. The operation and maintenance expense reported prior to the Transactions Date is not indicative of operation and maintenance expense incurred subsequent to the Transactions Date due to synergies in staffing, use of equipment and utilization of chemicals throughout fiscal year 2015, which has resulted in a decrease in operations and maintenance expenses from the previous fiscal year.

General and Administrative Expenses

Under the New Omnibus Agreement, Azure has the ability to determine the Services and the amount of such Services it provides to the Partnership. These general and administrative expenses are not comparable to the general and administrative expenses previously allocated to the Azure System from Azure. In addition, the Partnership's general and administrative expenses are not comparable to the historical Azure System’s general and administrative expenses because the Partnership's general and administrative expenses include the expenses associated with being a publicly traded master limited partnership whereas the Azure System was operated as a component of a private company.

Financing

In connection with the Transactions, the Partnership entered into the Credit Agreement with Wells Fargo Bank, National Association, as administrative agent, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and SG Americas Securities, LLC, (collectively, the “Lenders”). The Credit Agreement has a maturity date of February 27, 2018 and up to $231.7 million in commitments subsequent to the Third Amendment to the Credit

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Agreement. As a result, the Partnership's long-term debt and related charges are not comparable to the Azure System's historical long-term debt and related charges. We expect ongoing sources of liquidity to include cash generated from operations, our Credit Agreement and additional issuances of equity securities.

HOW WE EVALUATE OUR OPERATIONS

Our management uses a variety of financial and operational metrics to analyze the Partnership's performance. These metrics include: (i) throughput volume; (ii) Adjusted EBITDA; (iii) operating expenses; and (iv) capital spending.

Throughput Volume

The volume of natural gas and crude oil that we gather and transport depends on the level of production from natural gas and oil wells connected to our gathering systems and transloading facilities. Aggregate production volumes are impacted by the overall amount of drilling and completion activity because production must be maintained or increased by new drilling or other activity as the production rate of a natural gas and oil wells decline over time. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of natural gas, oil and NGLs, the cost to drill and operate a well, the availability and cost of capital, and environmental and government regulations. We generally expect the level of drilling to positively correlate with long-term trends in commodity prices. Similarly, production levels nationally and regionally generally tend to positively correlate with drilling activity, and we actively monitor producer drilling activity in the areas served by our gathering systems and transloading facilities to pursue new supply opportunities.

We must continually obtain new supplies of natural gas and crude oil to maintain or increase the throughput volume on our systems and our transloading facilities. Our ability to maintain or increase existing throughput volumes and obtain new supplies of natural gas and crude oil is impacted by:

- successful drilling activity within our dedicated acreage and areas of operations;
- the level of work-overs and recompletions of wells on existing pad sites to which our gathering systems and transloading facilities are connected;
- the number of new pad sites in our dedicated acreage awaiting lateral connections;
-

our ability to compete for volumes from successful new wells in the areas in which we operate outside of our existing dedicated acreage;

· our ability to utilize the remaining uncommitted capacity on, or add additional capacity to, our gathering and processing systems and our transloading facilities;

· our ability to gather natural gas and crude oil volumes that have been released from commitments with our competitors; and

· our ability to acquire or develop new systems with associated volumes and contracts.

Adjusted EBITDA

We believe that Adjusted EBITDA is a widely accepted financial indicator of our operational performance and our ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is used as supplemental financial measures by management and external users of our financial statements, such as investors, commercial banks and research analysts, to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; 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.

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We define EBITDA as net income (loss), plus: (i) interest expense; (ii) income tax expense; and (iii) depreciation and amortization expense. We define Adjusted EBITDA as EBITDA, plus adjustments associated with certain non-cash and other items.

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

In thousands	Year Ended December 31, 2015	2014	Period from November 15, 2013 to December 31, 2014	Azure System Predecessor Period from January 1, 2013 to November 14, 2013
Net loss	$ (222,425)	$ (6,820)	$ (1,323)	$ (7,886)
Add (Deduct):				
Interest expense	11,333	15,149	1,855	3,167
Income tax expense	686	213	26	118
Depreciation and amortization expense	20,957	7,961	958	9,999
Non-cash equity based compensation	932	—	—	—
Impairments	215,758	228	—	659
Gain on sale of equipment	(237)	—	—	—
Other adjustments (1)	6,088	2,799	502	(902)
Deferred revenue (2)	7,163	6,275	684	—
Adjusted EBITDA	$ 40,255	$ 25,805	$ 2,702	$ 5,155

(1) Other adjustments consists of non-recurring and non-cash items, including: (i) non-recurring expenses associated with the Transactions and Transition Services Agreement between the Partnership and Azure; and (ii) non-cash volumetric natural gas imbalance adjustments.
(2) Adjustments also relate to the deferred revenue associated with our minimum revenue contract ("MRC") and several MVC agreements. We include a proportional amount of the expected MRC/MVC cash receipts in each quarter in respect of the annual period for which we actually receive the payment to ensure our Adjusted EBITDA reflects the amount of cash we are entitled to receive on an annual basis under these MRC/MVC agreements.

Adjusted EBITDA is not a financial measure presented in accordance with GAAP. We believe that the presentation of this non-GAAP financial measure will provide useful information to investors in assessing our financial condition and results of operations. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss). This measure should not be considered as an alternative to operating income, net income (loss), or any other measure of financial performance presented in accordance with GAAP. The non-GAAP financial measure has important limitations as an analytical tool because it excludes some but not all items that affect net income. You should not consider this non-GAAP financial measure in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because the non-GAAP financial measure may be defined differently by other companies in our industry, our definition of may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Operating Expenses

We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. Direct labor costs, repair and non-capitalized maintenance costs, integrity management costs, treating chemical costs, utilities and contract services are the most significant portion of our operating expenses. These expenses are largely dependent on the volumes delivered through our gathering systems, processing plants and transloading facilities, and these expenses may fluctuate depending on the type of activities, such as repairs and maintenance and integrity management, performed during a specific period.

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Capital Spending

Our management seeks to effectively manage our maintenance capital expenditures, including turnaround costs. These capital expenditures relate to the maintenance and integrity of our pipelines and processing and transloading facilities. We capitalize the costs of major maintenance activities, or turnarounds, and depreciate the costs over the period until the next planned turnaround of the affected unit. We categorize maintenance capital expenditures as those that are made to maintain our asset base, operating capacity or operating income, or to maintain the existing useful life of any of our capital assets, in each case over the long term. Examples of maintenance capital expenditures are expenditures for the repair, refurbishment and replacement of our assets, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations. In addition, we may designate a portion of our maintenance capital expenditures to connect new wells to maintain throughput to the extent such capital expenditures are necessary to maintain, over the long term, our operating capacity or operating income.

Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. Growth capital expenditures are cash expenditures to construct new midstream infrastructure, including those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues, or increase system throughput or capacity from current levels. Examples of growth capital expenditures include the construction, development or acquisition of additional gathering pipelines, compressor stations, processing plants, transloading facilities and new well connections, in each case to the extent such capital expenditures are expected to expand our operating capacity or operating income. In the future, if we make acquisitions that increase system throughput or capacity, the associated capital expenditures will also be considered expansion capital expenditures.

General Trends and Outlook

The prices of crude oil and natural gas have historically been volatile. For example, for the year ended December 31, 2014, the NYMEX prompt month settle price ranged from a high of $107.26 per barrel to a low of $54.12 per barrel. For the year ended December 31, 2015, the range narrowed to a high of $61.43 per barrel to a low of $34.73 per barrel. As of December 31, 2015, the NYMEX natural gas futures price was $2.34 per MMBtu compared with $2.89 per MMBtu as of December 31, 2014 and $4.23 per MMBtu as of December 31, 2013. Substantial declines in crude oil and natural gas prices, particularly prolonged declines, can have negative effects on crude oil and natural gas producers including:

- reduced volume of crude oil and natural gas that can be produced economically;
- reduced revenue, operating income and cash flows;
- delayed or postponed capital projects; and
- limited access to or increased cost of capital, such as equity and long-term debt.

The substantial decline in these commodity prices since mid-2014 and continuing throughout 2015 and into 2016, have affected a number of companies in the oil industry, including our customers. While we do not have significant direct exposure to commodity prices, we are exposed to a reduction in volumes to be transported and processed as a result of lower prices. We experienced such reductions in 2015 and expect these reductions to continue in 2016.

Capital markets activity and cost of capital

After multiple years of near-record low interest rates, the credit markets reversed in 2015 and borrowing costs increased for virtually all crude oil and natural gas industry-related borrowers. Additionally, in December 2015, the Federal Reserve announced that it would raise its benchmark federal-funds rate from near zero to a range between 0.25% and 0.50%, the first such increase since 2006. The Federal Reserve also announced its intent to continue to raise interest rates gradually in the future, to the extent that economic growth continues. Capital markets conditions, including but not limited to higher borrowing costs, could affect our ability to access the debt capital markets to the extent necessary to fund our future growth. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise debt

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capital on acceptable terms, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

Current Operating Environment

In 2016, our objectives will be focused on maintaining stable distributable cash flows from our existing and newly acquired Legacy System and ETG System and executing on 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 operating strategy, which includes maximizing opportunities provided by our relationship with Azure, capitalizing on organic expansion opportunities and potentially pursuing strategic and accretive third party acquisitions, in each case in order to maintain and grow our distributable cash flows.

Our ability to reinstate and ultimately grow cash distributions depends on our ability to maintain and increase revenues in our current areas of operations and, when prudent, to make acquisitions that increase the amount of cash generated from our operations on a per-unit basis, along with other factors. The size, timing and contribution of such acquisitions, if any, to our results of operations cannot be reasonably estimated. Furthermore, there are a number of risks and uncertainties that could cause our current expectations to change, including, but not limited to: (i) the ability to reach agreement on acceptable terms with third parties; (ii) prevailing conditions and outlook in the natural gas and crude oil industries and markets; and (iii) our ability to obtain financing on acceptable terms from commercial banks, the capital markets or other sources.

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RESULTS OF OPERATIONS

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

The following table presents selected financial data for each of the years ended December 31, 2015 and 2014.

In thousands, except operating data	Year Ended December 31, 2015	2014	Change
Operating Revenues:			
Natural gas, NGLs and condensate revenue	$ 21,720	$ 51,484	$ (29,764)
Gathering, processing, transloading and other fee revenue	58,872	23,237	35,635
Total operating revenues	80,592	74,721	5,871
Operating Expenses:			
Cost of natural gas and NGLs	18,408	38,042	(19,634)
Operation and maintenance	20,776	13,714	7,062
General and administrative	14,183	5,812	8,371
Depreciation and amortization	20,957	7,961	12,996
Impairments	215,758	228	215,530
Total operating expenses	290,082	65,757	224,325
Operating income (loss)	(209,490)	8,964	(218,454)
Interest expense	11,333	15,149	(3,816)
Other expense, net	916	422	494
Net loss before income tax expense	(221,739)	(6,607)	(215,132)
Income tax expense	686	213	473
Net loss	$ (222,425)	$ (6,820)	$ (215,605)
Key performance metrics:			
Adjusted EBITDA (1)	$ 40,255	$ 25,805	
Operating data:			
Average throughput volumes of natural gas (MMcf/d)	300	261	
Average volume of processed gas (MMcf/d)	152		
Transloading Volumes (Bbls/d)	22,459		

(1) Adjusted EBITDA is not a financial measure presented in accordance with GAAP. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP, please see - “How We Evaluate Our Operations.”

Revenues

Natural gas, NGLs and condensate revenue decreased by $29.8 million to $21.7 million for the year ended December 31, 2015, as compared to $51.5 million for the year ended December 31, 2014. This decrease was primarily attributed to the Azure System, which recognized revenue of $15.6 million for the year ended December 31, 2015 compared to $51.5 million for the year ended December 31, 2014. The decrease in the Azure System was primarily attributable to the Legacy System, which decreased $30.6 million while the ETG System decreased $5.3 million. This decrease was a result of declines in commodity prices and lower volumes. The decrease in natural gas, NGLs and condensate revenue attributed to the Azure System was partially offset by an increase of $6.1 million in revenue attributed to the Partnership's historical midstream assets, which are included within the consolidated results of operations subsequent to the Transaction Date.

Gathering, processing, transloading and other fee revenue increased by $35.6 million to $58.9 million for the year ended December 31, 2015, as compared to $23.2 million for the year ended December 31, 2014. This increase was primarily attributable to the Partnership's historical midstream assets, which recognized revenue of $36.4 million and is included within the consolidated results of operations subsequent to the Transactions Date. This increase was partially offset by a decrease of $0.8 million attributable to the Azure System due to lower volumes.

Cost of Natural Gas and NGLs

Cost of natural gas and NGLs decreased by $19.6 million to $18.4 million for the year ended December 31, 2015, as compared to $38.0 million for the year ended December 31, 2014. This decrease was primarily attributed to the Azure System, which recognized cost of $38.0 million for the year ended December 31, 2015 compared to $11.9 million for the year ended December 31, 2014. The decrease in the Azure System was primarily attributable to the Legacy System, which decreased $21.9 million while the ETG System decreased $4.2 million. This decrease was a result of lower commodity prices and volumes purchased, which directly correlates to the decrease in natural gas, NGLs and condensate revenue for the period. The decrease in cost of natural gas and NGLs attributed to the Azure System was partially offset by an increase of $6.5 million attributable to the Partnership's historical midstream assets, which are included within the consolidated results of operations subsequent to the Transaction Date.

Operation and Maintenance Expense

Operation and maintenance expense increased by $7.1 million to $20.8 million for the year ended December 31, 2015, as compared to $13.7 million for the year ended December 31, 2014. This increase was a result of a $9.4 million increase attributable to the Partnership's historical midstream assets, which are included within the consolidated results of operations subsequent to the Transaction Date. This increase was partially offset by a decrease of $2.3 million in the Azure System’s operations and maintenance expense period over period, and was a result of lower compression rental, asset integrity management and repairs and maintenance expenses.

General and Administrative Expense

General and administrative expense increased by $8.4 million to $14.2 million for the year ended December 31, 2015, as compared to $5.8 million for the year ended December 31, 2014. This increase was due to the Partnership's MLP cost structure as compared to the allocated cost associated with the Azure System.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $13.0 million to $21.0 million for the year ended December 31, 2015, as compared to $8.0 million for the year ended December 31, 2014. This increase was primarily the result of $12.4 million increase attributable to the Partnership's historical midstream assets, which were adjusted to fair value in connection with the business combination and are included within the consolidated results of operations subsequent to the Transaction Date. In addition, depreciation and amortization expense increased $0.6 million related to the Azure System.

Impairments

Impairments increased due to the full write-off of $215.8 million of goodwill in September 2015.

As part of our annual assessment of goodwill, and in light of the continued deterioration of energy related commodity prices and an extended decline in the Partnership’s unit price, we engaged a third party valuation firm to perform a goodwill impairment analysis. The Partnership has determined that the carrying amount of goodwill attributable to the Marlin Midstream assets was fully impaired as a result of the significant declines in natural gas and NGL prices affecting future volumes.

Other Expense, Net

Other expense, net increased $0.5 million to $0.9 million for the year ended December 31, 2015, as compared to $0.4 million for the year ended December 31, 2014. This increase was attributable to the ETG System, which increased $1.1 million primarily related to transaction costs allocated by AME in connection with the Contribution Agreement and a $0.2 million increase attributable to the Partnership's historical midstream assets, which are included within the consolidated results of operations subsequent to the Transaction Date. This increase was partially offset due to

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$0.8 million of other income attributable to the Legacy System related to payments received for the release of acreage dedications.

Interest Expense

Interest expense decreased by $3.8 million to $11.3 million for the year ended December 31, 2015, as compared to $15.1 million for the year ended December 31, 2014. The decrease in interest expense is due to interest calculated on an average debt balance of $196.7 million at an average rate of 3.5% for the year ended December 31, 2015, versus interest calculated and allocated to the Azure System on an average debt balance of $192.0 million at an average interest rate of 6.5% related to the Azure Credit Agreement.

Income Tax Expense

Income tax expense increased by $0.5 million to $0.7 million for the year ended December 31, 2015, as compared to $0.2 million for the year ended December 31, 2014. The increase in income tax expense is due to the Partnership's revised calculation subsequent to the drop down of Azure ETG. The cumulative difference between the net book value of fixed assets for tax versus GAAP increased and as a result the income tax expense and deferred income tax expense increased for the period.

Year Ended December 31, 2014 Compared to the Period from November 15, 2013 to December 31, 2013 ("Azure 2013 Period") and the Period from January 1, 2013 to November 14, 2013 ("Predecessor 2013 Period")

The following table presents selected financial data for the year ended December 31, 2014, the Azure 2013 Period and the Predecessor 2013 Period.

In thousands, except operating data	Year Ended December 31, 2014	Period from November 15, 2013 to December 31, 2013	Azure System Predecessor Period from January 1, 2013 to November 14, 2013
Operating Revenues:			

Natural gas, NGLs and condensate revenue	$ 51,484	$ 5,534	$ 31,749
Gathering, processing, transloading and other fee revenue	23,237	3,325	9,514
Total operating revenues	74,721	8,859	41,263
Operating Expenses:			
Cost of natural gas and NGLs	38,042	4,505	21,054
Operation and maintenance	13,714	2,643	11,330
General and administrative	5,812	195	3,629
Depreciation and amortization	7,961	958	9,999
Impairments	228	—	659
Total operating expenses	65,757	8,301	46,671
Operating income	8,964	558	(5,408)
Interest expense	15,149	1,855	3,167
Other (income) expense, net	422	—	(807)
Net loss before income tax expense	(6,607)	(1,297)	(7,768)
Income tax expense	213	26	118
Net loss	$ (6,820)	$ (1,323)	$ (7,886)
Key performance metrics:			
Adjusted EBITDA (1)	$ 25,805	$ 2,702	$ 5,155
Operating data:			
Average throughput volumes of natural gas (MMcf/d)	261	209	189

(1) Adjusted EBITDA is not a financial measure presented in accordance with GAAP. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP, please see - “How We Evaluate Our Operations.”

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Revenues

The Azure System's total operating revenues were $74.7 million for the year ended December 31, 2014 compared to total operating revenues of $8.9 million for the Azure 2013 Period and $41.3 million for the Predecessor 2013 Period. Natural gas and NGL sales were $51.5 million for the year ended December 31, 2014 compared to natural gas and NGL sales of $5.5 million for the Azure 2013 Period and $31.8 million for the Predecessor 2013 Period. The increase in total natural gas and NGL sales revenue period over period is due to: (i) higher natural gas and NGL sales volumes and higher weighted average natural gas and NGL sales prices during the year ended December 31, 2014 as compared to the Azure 2013 Period and the Predecessor 2013 Period; and (ii) increased sales attributable to the contribution of the ETG System of $8.6 million for the year ended December 31, 2014 and $1.6 million for the Azure 2013 Period. Gathering services and other fees were $23.2 million for the year ended December 31, 2014 compared to gathering services and other fees of $3.3 million for the Azure 2013 Period and $9.5 million for the Predecessor 2013 Period. The primary reason for the increase in gathering services and other fees revenue was the higher volumes and prices discussed above.

Cost of Natural Gas and NGLs

The Azure System's cost of purchased gas and NGLs sold were $38.0 million for the year ended December 31, 2014 compared to the cost of purchased gas and NGLs sold of $4.5 million for the Azure 2013 Period and $21.1 million for the Predecessor 2013 Period. The increase in cost of purchased gas and NGLs sold is due to: (i) higher natural gas prices and higher volumes period over period, and correlates to the increase in natural gas and NGL sales during the periods; and (ii) increased costs attributable to the contribution of the ETG System of $7.4 million for the year ended December 31, 2014 and $1.6 million for the Azure 2013 Period.

Operation and Maintenance Expense

The Azure System's operating expense was $13.7 million for the year ended December 31, 2014 compared to operating expense of $2.6 million for the Azure 2013 Period and $11.3 million for the Predecessor 2013 Period. The increase in operating expense was due to the contribution of the ETG System of $6.9 million for the year ended December 31, 2014 and $1.1 million for the Azure 2013 Period. This increase related to the ETG System was almost entirely offset by decreases in operating expense due to continued focus on asset optimization, including moving and consolidating compression facility locations and the release of under-utilized rental compression and treating equipment.

General and Administrative Expense

General and administrative expenses allocated to the Azure System were $5.8 million for the year ended December 31, 2014 compared to the $0.2 million amount allocated during the Azure 2013 Period and the $3.6 million amount allocated during the Predecessor 2013 Period. The increase was primarily driven by: (i) non-recurring transition and transaction expenses that have been allocated to the Azure System and were incurred by Azure during the year ended December 31, 2014; and (ii) increased general and administrative expense attributable to the contribution of the ETG System of $1.4 million for the year ended December 31, 2014. These costs were partially offset by a reduction in corporate personnel expenses as Azure reduced the number of corporate personnel to better align with the needs of its newly acquired assets.

Depreciation and Amortization Expense

The Azure System's depreciation and amortization expense was $8.0 million for the year ended December 31, 2014 compared to depreciation and amortization expense of $1.0 million for the Azure 2013 Period and $10.0 million for the Predecessor 2013 Period. As a result of the application of purchase accounting, the Legacy System assets acquired and liabilities assumed by Azure were adjusted to their fair market values on November 15, 2013, and Azure assigned useful lives based on various factors, including age and historical data associated with the assets acquired. The fair market values and useful lives assigned were different than the Azure Predecessor resulting in the decrease in depreciation and amortization expense. This decrease was partially offset by increased depreciation and amortization expense attributable to the contribution of the ETG System of $2.6 million for the year ended December 31, 2014 and $0.3 million for the Azure 2013 Period.

Impairments

The Azure System recognized a $0.2 million impairment during the year ended December 31, 2014 compared to a $0.7 million impairment recognized during the Predecessor 2013 Period. These impairments resulted from adjusting the net book value of assets held for sale to their net realizable fair market value. There was no impairment recognized during the Azure 2013 Period.

Interest Expense

Interest expense allocated to the Azure System was $15.1 million for the year ended December 31, 2014 compared to interest expense of $1.9 million for the Azure 2013 Period and $3.2 million for the Predecessor 2013 Period. The increase is primarily driven by: (i) increased outstanding borrowings under the Azure credit facility, which have been allocated to the Azure System, compared to outstanding borrowings under the Azure credit facility, which have been allocated to the Azure System Predecessor; and (ii) increased interest expense attributable to the contribution of the ETG System of $4.5 million for the year ended December 31, 2014 and $0.6 million for the Azure 2013 Period.

Other (Income) Expense, net

The Azure System’s other expense, net was $0.4 million for the year ended December 31, 2014 compared to other income, net of $0.8 million for the Predecessor 2013 Period. Other expense, net of $0.4 million in 2014 relates to the settlement of residual condemnation cases acquired as part of the original acquisition of the Azure ETG system by Azure in 2013. Other income, net recognized by Azure System Predecessor in 2013 relates to the reimbursement of operating expenses by a producer for salt water disposal activities.

Income Tax Expense

The Azure System’s income tax expense was $0.2 million for the year ended December 31, 2014 compared to $0.1 million for the Predecessor 2013 Period. This increase relates to the Texas margin taxes as a result of increased Texas sourced revenues. This was a result of the Azure ETG acquisition in late 2013 by Azure, which is primarily Texas sourced.

LIQUIDITY AND CAPITAL RESOURCES

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

We expect ongoing sources of liquidity to include cash generated from operations and borrowings under our existing Credit Agreement subject to lender approval. We believe that cash generated from these sources will be sufficient to sustain operations. Management is continuing to consider alternatives to enhance the Partnership's liquidity and address concerns surrounding its ability to remain in compliance with the financial covenants under its Credit Agreement.

In the event our liquidity is insufficient, the Partnership may be unable to make quarterly cash distributions on all of our outstanding units at our minimum quarterly distribution rate.

Ability to Continue as a Going Concern

The precipitous decline in oil and natural gas prices during 2015 and into 2016 has had a significant adverse impact on our business, and has impacted the Partnership's ability to comply with financial covenants and ratios in the Credit Agreement. Based upon our current estimates and expectations for commodity prices in 2016, we do not expect

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to remain in compliance with all of the restrictive covenants contained in the Credit Agreement throughout 2016 unless those requirements are waived or amended. Absent a waiver or amendment, failure to meet these covenants and ratios would result in a default and, to the extent the applicable lenders so elect, an acceleration of the existing indebtedness, causing such debt of approximately $231.7 million to be immediately due and payable. The Partnership does not currently have adequate liquidity to repay all of its outstanding debt in full if such debt were accelerated.

Distributions

For the quarter ended December 31, 2015, we suspended distributions on our limited partner interests. Should the distributions be reinstated, the common unitholders will be entitled to receive the minimum quarterly distribution of $0.35 per unit in arrears for each quarter as to which the distributions were suspended. Payment of any such amount in arrears will be subject to board of directors' approval and compliance with the terms of our Partnership Agreement and the agreements governing our indebtedness. The board of directors will continue to evaluate the Partnership's ability to reinstate the distribution, although reinstatement of distributions is not expected in the near term absent substantial improvement in our operating performance and compliance with the terms of our Credit Agreement.

We are evaluating a number of strategies to strengthen the balance sheet and improve liquidity. However, other than the requirement in our Partnership Agreement to distribute all of our available cash each quarter, we have no obligation to make quarterly cash distributions in this or any other quarter, and our General Partner has considerable discretion to determine the amount of our available cash each quarter.

Credit Agreement

On February 27, 2015, we entered into the Credit Agreement with the Lenders. The maturity date of the Credit Agreement is February 27, 2018.

If we fall out of compliance with the covenants set forth in our Credit Agreement and are unable to reach an agreement with our banks, find acceptable alternative financing or complete asset sales, the lenders could accelerate the outstanding indebtedness, which would make it immediately due and payable. Current market conditions may put limitations on our ability to issue new debt or equity securities in the public or private markets. The ability of oil and gas companies to access the equity and high yield debt markets has been significantly limited since the significant decline in commodity prices throughout 2015 and into 2016.

Amendment to the Credit Agreement

Due to the extended decline in commodity prices, the Partnership determined that there was a significant risk of triggering a covenant default under the Credit Agreement. Accordingly, in October 2015, the Partnership entered into the second amendment to the Credit Agreement (the "Second Amendment") and the first amendment to the security agreement. Among other things, the Second Amendment reduced the borrowing capacity under the Credit Agreement to $238.0 million and provided for more favorable financial condition covenants, including amending our maximum permitted consolidated leverage ratio.

Our maximum permitted consolidated leverage ratio as a result of the Second Amendment is 6.00 times debt to consolidated adjusted EBITDA for the quarterly period ended December 31, 2015, 5.00 times for the quarterly period ended March 31, 2016 and 5.00 for the last day of any fiscal quarter ending after March 31, 2016 during a Specified Acquisition Period as defined in the Second Amendment, or 4.50 for the last day of any fiscal quarter outside of a Specified Acquisition Period.

Under the terms of the Second Amendment, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default exists. In addition, under the Second Amendment, future distributions are contingent upon the maintenance of certain leverage ratios, as detailed in the Second Amendment. There is substantial doubt that the Partnership will be able to comply with the financial covenants over the next four quarters. As part of its balance sheet management, the Partnership is evaluating several alternatives to bolster its capital and liquidity position, including but not limited to asset sales. The Partnership's ability to comply with the financial covenants and to pay

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distributions over the next four quarters is uncertain and will depend upon the Partnership's ability to reduce debt, increase its liquidity, or increase its Adjusted EBITDA due to a rebound in commodity prices and a related increase in drilling activity by the producers supplying its volumes.

We incurred $0.7 million in fees associated with the Second Amendment.

We were in compliance with all of our financial covenants under the Credit Agreement as of December 31, 2015. However, given the lower commodity prices in 2015 and 2016, we would have exceeded the maximum permitted consolidated leverage ratio set forth in our bank credit facility at the end of the first quarter of 2016, which required us to seek a waiver or amendment from our bank lenders.

On March 29, 2016, the Partnership entered into the third amendment to the Credit Agreement ("Third Amendment"). The Third Amendment waived the affirmative covenant that stated if the Partnership's annual financial statements, prepared in accordance with generally accepted accounting standards, contained any going concern qualification an event of default would result, for the year ended December 31, 2015. Additionally, the Third Amendment waived certain other events of default until June 30, 2016. Under the terms of the Third Amendment, we are still prohibited from declaring or paying any distributions to unitholders if a default or event of default exists.

The Credit Agreement requires that all domestic restricted subsidiaries guarantee our obligations and the obligations of the subsidiary guarantors under: (i) the Credit Agreement and other loan documents; (ii) certain hedging agreements and cash management agreements with lenders and affiliates of lenders; and (iii) all such obligations be secured by a security interest in substantially all of our assets and the assets of our subsidiary guarantors, in each case, subject to certain customary exceptions.

Borrowings under the Credit Agreement bear interest at the LIBOR Rate (as defined in the Credit Agreement) plus an applicable margin of 2.75% to 3.75% or the Base Rate, as defined in the Credit Agreement, plus an applicable margin of 1.75% to 2.75%, in each case, based on the Consolidated Total Leverage Ratio, as defined in the Credit Agreement.

All of the Partnership's domestic restricted subsidiaries guarantee our obligations under the Credit Agreement, and all such obligations are secured by a security interest in substantially all of our assets, in each case, subject to certain customary exceptions. The Credit Agreement contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict our ability and the ability of our subsidiaries to: (i) incur additional debt; (ii) grant certain liens; (iii) make certain investments; (iv) engage in certain mergers or consolidations; (v) dispose of certain assets; (vi) enter into certain types of transactions with affiliates; and (vii) make distributions, with certain exceptions, including the distribution of Available Cash, as defined in the Partnership Agreement, if no default or event of default exists. As of December 31, 2015, we were in compliance with all of our covenants associated with the Credit Agreement, as amended.

Azure System and the Azure System Predecessor Credit Agreements

On November 15, 2013, Azure closed on a $550.0 million Senior Secured Term Loan B, the ("TLB") maturing November 15, 2018, and a $50.0 million Senior Secured Revolving Credit Facility, the ("Revolver") and collectively with the TLB, the ("Azure Credit Agreement"), with a maturity of November 15, 2017. Borrowings under the Azure Credit Agreement are unconditionally guaranteed, jointly and severally, by all of the Azure subsidiaries and are collateralized by first priority liens on substantially all of existing and subsequently acquired assets and equity. The Azure Credit Agreement served as the sole borrowing agreement applicable for the Azure System up to the Transaction Date. In addition, substantially all of Azure's subsidiaries, including the Azure System, served as guarantors and pledger's with respect to the Azure Credit Agreement.

Public Offering of Partnership Common Units

On June 17, 2015, we and the General Partner entered into an Underwriting Agreement related to the Offering. The Offering closed on June 22, 2015. The Partnership received net proceeds from the sale of the common units sold in the Offering of approximately $48.3 million including the proportionate capital contribution by the General Partner to maintain its 1.93% general partner interest and after deducting the underwriting discount and estimated offering expenses payable by the Partnership.

On July 17, 2015, underwriters of the Partnership's completed Offering, exercised their option to purchase an additional 90,000 common units. Total net proceeds from the sale of these additional common units after deducting underwriting discounts and commissions and estimated offering expenses, was approximately $1.2 million.

CASH FLOWS

The following table summarizes net cash flows provided by (used in) operating activities, investing activities and financing activities for the years ended December 31, 2015 and 2014:

In thousands	Year Ended December 31, 2015	2014	Change
Net cash provided by (used in):			
Operating activities	$ 10,455	$ 8,179	$ 2,276
Investing activities	$ 39,170	$ (13,839)	$ 53,009
Financing activities	$ (42,114)	$ 5,660	$ (47,774)

Operating Activities. Cash flows provided by operations for the year ended December 31, 2015 were $10.5 million compared to cash flows provided by operations of $8.2 million for the year ended December 31, 2014. The net source of cash flows from operations was primarily due to: (i) higher depreciation and amortization expense of $13.0 million related to the Partnership's historical midstream assets, which were adjusted to fair value in connection with the Transactions and are included within the consolidated results of operations subsequent to the Transaction Date; (ii) higher unit based compensation related to the Marlin Midstream Partners, LP 2013 Long-Term Incentive Plan ("LTIP") of $0.9 million; and (iii) higher deferred income tax liability of $0.7 million, partially offset by; (iv) $11.8 million from changes in operating assets and liabilities; (v) decrease in amortization of deferred financing costs of $0.2 million; and (vi) gain on sale of equipment of $0.2 million.

Investing Activities. Cash flows provided by investing activities were $39.2 million for the year ended December 31, 2015 compared to cash flows used in investing activities of $13.8 million for the year ended December 31, 2014. The cash flows provided by investing activities for the year ended December 31, 2015 were primarily associated with the $117.3 million in cash acquired in the Transactions, which represents the net cash held by the Partnership immediately prior to the business combination. The net cash balance held by the Partnership immediately prior to the business combination was assumed to be the $180.8 million in cash borrowed under the Credit Agreement less the $63.0 million paid in connection with the redemption of 90 IDR Units from NuDevco, partially offset by a $76.2 million distribution related the Contribution Agreement and $4.7 million of capital expenditures. The cash flows used in investing activities during the year ended December 31, 2014 were associated with capital expenditures of $14.2 million incurred by the Azure System during the period, partially offset by proceeds from the sale of equipment of $0.4 million.

Financing Activities. Cash flows used in financing activities were $42.1 million for the year ended December 31, 2015 compared to cash flows provided by financing activities of $5.7 million for the year ended December 31, 2014. The cash flows used in financing activities for the year ended December 31, 2015 were primarily associated with: (i) $99.5 million in cash distribution related to the Transactions; (ii) $48.5 million repayment of long-term debt on our Credit Agreement from proceeds from the Offering; (iii) $23.2 million quarterly distributions to unitholders; (iv) $15.0 million repayment of long-term debt related to the Partnership's existing credit facility in connection with the Transactions; (v) $3.8 million of consideration paid in excess of net book value in connection with the Contribution Agreement; (vi) $3.7 million repayment of long-term debt related to the Azure Credit Agreement; and (vii) $1.1 million of payments related to deferred financing costs, partially offset by (viii) $99.5 million of borrowings under our Credit Agreement; (ix) $49.5 million proceeds from the Offering; and (x) $3.7 million of net proceeds related to parent company net investment. The cash flows used in financing activities for the year ended December 31, 2014 were primarily associated with $10.1 million in allocated repayments of long-term debt under the Azure Credit Agreement, partially offset by $15.9 million of net proceeds related to parent company net investment.

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The following table summarizes net cash flows provided by (used in) operating activities, investing activities and financing activities for the year ended December 31, 2014, the period from November 15, 2013 to December 31, 2013, the ("Azure 2013 Period") and the period from January 1, 2013 to November 14, 2013, the ("Predecessor 2013 Period"):

In thousands	Year Ended December 31, 2014	Period From November 15, 2013 to December 31, 2013	Azure System Predecessor Period From November 15, 2013 to December 31, 2013
Net cash provided by (used in):			
Operating activities	$ 8,179	$ (384)	$ 3,590
Investing activities	$ (13,839)	$ (212,123)	$ (13,989)
Financing activities	$ 5,660	$ 212,507	$ 10,399

Operating Activities. Operating cash flow has been the source of liquidity for the Azure System and the Azure System Predecessor. Generally, the Azure System and Azure System Predecessor's operating cash flows increase or decrease due to the same factors that impact income (loss) from operations. Consequently, changes in operating cash flows since the year ended December 31, 2012 were primarily driven by the fluctuations in volume and price of the natural gas and NGLs purchased, sold, gathered, compressed and treated by the Azure System and Azure System Predecessor's assets.

Investing Activities. Cash flows used in investing activities were $13.8 million for the year ended December 31, 2014 compared to cash flows used in investing activities of $212.1 million for the Azure 2013 Period and cash flows used in investing activities of $14.0 million for the Predecessor 2013 Period. The cash flows used in investing activities for the year ended December 31, 2014 were primarily associated with $14.2 million in capital expenditures partially offset by proceeds from the sale of equipment of $0.4 million. Cash used in investing activities for the Azure 2013 Period reflect the allocated Legacy System purchase price of $212.5 million, capital expenditures of $1.1 million, partially offset by cash received in the ETG System acquisition of $1.5 million. Cash used in investing activities for the Predecessor 2013 Period related to capital expenditures.

Financing Activities. Cash flows provided by financing activities were $5.7 million for the year ended December 31, 2014 compared to cash flows provided by financing activities of $212.5 million for the Azure 2013 Period and cash flows provided by financing activities of $10.4 million for the Predecessor 2013 Period. Cash flows provided by financing activities for the year ended December 31, 2014 were due to parent company net investment, as described below, of $15.9 million, partially offset by allocated repayments related to the Azure Credit Agreement of $10.1 million and allocated payments of deferred financing costs of $0.2 million. Cash flows provided by financing activities for the Azure 2013 Period were due to allocated borrowings related to the Azure Credit Agreement of $202.1 million to facilitate the acquisition of the Legacy System, parent company net investment of $18.4 million, partially offset by allocated payments of deferred financing costs of $7.9 million. Cash flows provided by financing activities for the Predecessor 2013 Period were due to parent company net investment of $36.9 million partially offset by allocated borrowings related to the Azure Credit Agreement of $26.5 million.

Parent Company Net Investment

Azure's net investment in the operations of the Azure System and Azure System Predecessor is presented as parent company net investment within the respective period's financial statements. Parent company net investment represents the accumulated net earnings of the operations and the accumulated net contributions from Azure. Net contributions from Azure during the periods presented were primarily comprised of intercompany operations and maintenance expense, cash clearing and other financing activities, and debt and general and administrative costs allocations to the Azure System and Azure System Predecessor.

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CAPITAL EXPENDITURES

Our operations require investments to expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of maintenance capital expenditures and expansion capital expenditures. Maintenance capital expenditures are cash expenditures, including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets, made to maintain our long-term operating income or operating capacity. Expansion capital expenditures include expenditures to acquire assets and expand existing facilities that increase throughput capacity on our pipelines, processing plants and crude oil logistics assets. Based on current market conditions, we expect to be able to fund our activities for 2016 with cash flows generated from our operations and available cash on hand.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations.

Going forward, our capital requirements will consist of the following:

- maintenance capital expenditures are cash expenditures that are made to maintain our asset base, operating capacity or operating income, or to maintain the existing useful life of any of our capital assets, in each case over the long term. Examples of maintenance capital expenditures are expenditures for the repair, refurbishment and replacement of our assets, to maintain equipment reliability, integrity and safety, and to address environmental laws and regulations. In addition, we may designate a portion of our maintenance capital expenditures to connect new wells to maintain throughput to the extent such capital expenditures are necessary to maintain, over the long term, our operating capacity or operating income. We capitalize the costs of major maintenance activities, or turnarounds, and depreciate the costs over the expected useful life of such maintenance cost. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement; and

- growth capital expenditures are cash expenditures to construct new midstream infrastructure, including those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues, or increase system throughput or capacity from current levels. Examples of growth capital expenditures include the construction, development or acquisition of additional gathering pipelines, compressor stations, processing plants, and new well connections, in each case to the extent such capital expenditures are expected to expand our operating capacity or operating income. In the future, if we make acquisitions that increase system throughput or capacity, the associated capital expenditures will also be considered growth capital expenditures.

Our ability to pay distributions to our unitholders, fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry, some of which are beyond our control and our ability to access the capital markets for debt and equity capital.

OFF-BALANCE SHEET ARRANGEMENTS

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

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CONTRACTUAL OBLIGATIONS

A summary of our contractual obligations as of December 31, 2015 is as follows:

In thousands	2016	2017	2018	2019	2020	Thereafter	Total
Operating lease agreements (1)	$ 626	$ 399	$ 290	$ 274	$ 274	$ 1,032	$ 2,895
Long-term debt (2)	11,961	11,961	233,603	—	—	—	257,525
Total	$ 12,587	$ 12,360	$ 233,893	$ 274	$ 274	$ 1,032	$ 260,420

(1) The contractual obligations associated with operating lease agreements relate to various midstream property and equipment operating leases that are used in our gathering, processing and transloading operations and have terms of greater than one year.

(2) The contractual obligations associated with long-term debt and interest expense relate to obligations under our Credit Agreement. The Credit Agreement has a maturity date of February 27, 2018, and we have estimated the outstanding borrowings as of December 31, 2015 will be paid at maturity. We have estimated a weighted average interest rate of 5.16% in determining the future interest obligations associated with the Credit Agreement.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical.

The following updates our critical accounting policies.

Intangible Assets

Intangible assets consist of the Partnership's existing customer relationships, and were identified as part of the purchase price allocation to the Partnership's assets acquired by the Azure System Predecessor. The customer relationship intangible assets are amortized on a straight-line basis over the expected period of benefits of the customer relationship, which we have concluded is a ten year period.

Goodwill

Goodwill represents consideration paid in excess of the fair value of the identifiable assets acquired in a business combination. We evaluate goodwill for impairment on an annual basis, and whenever events or changes indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Goodwill is tested for impairment using a two-step quantitative test. The first step compares the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit exceeds the carrying amount, the goodwill is not considered impaired. If the fair value of the reporting unit does not exceed the carrying amount of the reporting unit, the second step compares the implied fair value of goodwill to the carrying value of goodwill. If the carrying amount of goodwill exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied value is recognized as an impairment in the statement of operations. See Note 8 "Goodwill" to the consolidated financial statements included in this Annual Report.

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

In general, we recognize revenue from customers when all of the following criteria are met: persuasive evidence of an exchange arrangement exists; delivery has occurred or services have been rendered; the price is fixed or determinable; and collectability is reasonably assured.

We utilize extensive estimation procedures to determine the sales and cost of gas, NGL, condensate or crude oil purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as “actualization”. Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month's accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: (i) actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; (ii) liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; (iii) NGL composition of purchases, sales and inventory being different than estimated; (iv) the estimated impact of weather patterns being different from the actual impact on sales and purchases; and (v) pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

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

We calculate depreciation expense using the straight-line method over the estimated useful lives of our property, plant and equipment. We assign asset lives based on reasonable estimates when an asset is placed into service. We periodically evaluate the estimated useful lives of our property, plant and equipment and revise our estimates when and as appropriate. Because of the expected long useful lives of the property, plant and equipment, we depreciate our property, plant and equipment over periods ranging from 5 years to 45 years. Changes in the estimated useful lives of the property, plant and equipment could have a material adverse effect on our results of operations.

Impairment of Long-Lived Assets

In accordance with FASB ASC 360-10-05, we evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, NGLs and crude oil, volume of gas, NGLs and crude oil available to the asset, markets available to the asset, operating expenses, and future natural gas, NGL product and crude oil prices. The amount of availability of gas, NGLs and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas and crude oil prices.

Projections of gas, NGL and crude oil volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

· changes in general economic conditions in regions in which our markets are located;

· the availability and prices of natural gas, NGLs, crude oil and condensate supply;

· our ability to negotiate favorable sales agreements;

· the risk that natural gas, NGLs, crude oil and condensate exploration and production activities will not occur or be successful;

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- our dependence on certain significant customers, producers and transporters of natural gas, NGLs, crude oil and condensate; and

- competition from other midstream companies, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

Accounting for Awards under the Long-term Incentive Plan

In connection with the Partnership's IPO, in July 2013, the board of directors of the General Partner adopted the LTIP. Individuals who are eligible to receive awards under the LTIP include: (i) our employees and the employees of NuDevco Midstream Development and its affiliates; (ii) directors of the Partnership’s General Partner; and (iii) consultants. The LTIP provides for the grant of unit options, unit appreciation awards, restricted units, phantom units, distribution equivalent rights, unit awards, profits interest units, and other unit-based awards. The maximum number of common units issuable under the LTIP is 1,750,000.

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

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

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

Subsequent to the closing of the Transactions, we awarded phantom units under the LTIP to certain named executive officers and employees of the General Partner. Each phantom unit is the economic equivalent of one common unit of the Partnership and entitles the grantee to receive one common unit or an amount of cash equal to the fair market value of a common unit upon the vesting of the phantom unit. The phantom units shall vest in three equal annual installments with the first installment vesting on July 1, 2016. In addition, we awarded common units under the LTIP to an employee of the General Partner, which vested immediately upon issuance.

NEW ACCOUNTING STANDARDS

Accounting standard setting organizations frequently issue new or revised accounting rules and pronouncements. We regularly review new accounting rules and pronouncements to determine their affect, if any, on our financial statements.

In February 2015, the Financial Accounting Standards Board ("FASB") issued a new accounting pronouncement to respond to stakeholders’ concerns about the current accounting for consolidation of certain legal entities. The update provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporations and securitization structures, should be consolidated. The update is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The update is effective for us beginning on January 1, 2016, and will have no effect on our consolidated financial statements or related disclosures.

In September 2015, the FASB issued a new accounting standard, which eliminates the requirement for an acquirer to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. The standard is effective for public business entities for annual periods, including interim periods within those annual periods, beginning after December 15, 2015. For all other entities, the standard is effective for fiscal years beginning after December 15, 2016, and interim periods within fiscal years beginning after December 15, 2017. Early adoption is permitted. The update is effective for us beginning on January 1, 2016.

In April 2015, the FASB issued a new accounting standard that simplifies the presentation of debt issuance costs. The amended guidance requires that debt issuance costs related to a recognized debt liability be presented within the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The Partnership will be required to adopt the guidance effective January 1, 2016. The standard will only affect the presentation of the Partnership's consolidated balance sheet and does not affect any of the Partnership's other financial statements.

In May 2014, the FASB and International Accounting Standards Board jointly issued a comprehensive new revenue recognition standard that will supersede nearly all existing revenue recognition guidance under GAAP and International Financial Reporting Standards. The standard’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The Partnership will be required to adopt this standard beginning in the first quarter of 2018. The adoption could have a significant impact on the consolidated financial statements, however management is currently unable to quantify the impact.

In August 2014, the FASB issued ASU 2014-15, "Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern (Subtopic 205-40)". The guidance will require management to evaluate whether there are conditions and events that raise substantial doubt about the company's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Additionally, management will be required to provide certain footnote disclosures if it concludes that substantial doubt exists or when it plans to alleviate substantial doubt about the company's ability to continue as a going concern. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and for annual and interim periods thereafter.

There are currently no other recent accounting pronouncements that have been issued that we believe will materially affect our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Interest Rate Risk

We have exposure to changes in interest rates under our amended Credit Agreement. The credit markets continues to produce an environment of low interest rates. It is possible that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. Interest rates on our Credit Agreement, which is under floating interest rates, and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly. For the year ended December 31, 2015, a 1% change in the interest rate under our Credit Agreement would have resulted in a $2.3 million change in interest expense.

Commodity Price Risk

Energy commodity prices can affect our profitability indirectly by influencing the level of drilling and production activity by our producer customers, the willingness of our non-producer customers to purchase natural gas for processing and the volumes of natural gas delivered to us for processing by all of our customers.

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Beginning in the second half of 2014 and continuing through the issuance of these financial statements, commodity prices have experienced increased volatility. In particular, natural gas, crude oil and NGL prices have decreased significantly. As a result of the decline in commodity prices and associated decline in upstream drilling activity, we have experienced a decline in the growth in volume of natural gas we gather and process for our customers.

In order to mitigate the effects of commodity price volatility substantially all of our revenues and the related cost of natural gas, NGLs and condensate revenues are generated under fee-based commercial agreements, the substantial majority of which have MVCs. We believe these commercial arrangements will help promote adequate cash flows and minimize direct commodity price exposure. Accordingly, we do not plan to enter into any derivative contracts to manage our exposure to commodity price risk, and, as a result of our limited exposure to commodity price risk under our fee-based commercial agreements, we do not plan to enter into hedging arrangements to manage such risk.

Counterparty and Customer Credit Risk

For the year ended December 31, 2015, we had two customers that each accounted for more than 10% of our revenues. Those customers were AES, which accounted for 36.1% of our revenues and BP, which accounted for 11.8% of our revenues.

Per the terms of our settlement agreement with AES, our three-year fee-based gathering and processing agreement with AES at our Panola County processing facilities will be terminated. Under this agreement, AES paid 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. We will have to replace the existing contract with new arrangements with other customers if we are to continue operations at this facility. AES has historically been our sole customer with respect to our crude oil logistics business, and we have derived the substantial majority of our transloading revenues from AES. AES contracts represented 100% of the capacity at our Wildcat, Big Horn, and East New Mexico facilities. The AES contract terminations have materially and adversely affected our crude oil logistics business.

If any customer that accounts for more than 10% of our revenues were to default on their contract, or if we were unable to renew a contract with them on favorable terms, we may not be able to replace such customers in a timely fashion, on favorable terms or at all. In any of these situations, our revenues and cash flows and our ability to make cash distributions to our unitholders would be materially and adversely affected.

During the first quarter of 2016, AES was delinquent in paying amounts invoiced under its gathering and processing contracts, as well as its logistics contracts with subsidiaries of the Partnership. The contracts have provisions requiring AES to make payments based on MVCs. AES caused its bank to issue a $15.0 million letter of credit to the administrative agent under our Credit Agreement to secure the amount of its obligations under its logistics contracts. See Item 1 and 2, "Business and Properties - Recent Developments" for further discussion of the AES contract terminations.

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Item 8. Financial Statements and Supplementary Data

AZURE MIDSTREAM PARTNERS, LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

The Board of Directors

Azure Midstream Partners GP, LLC:

We have audited the accompanying consolidated balance sheets of Azure Midstream Partners, LP and subsidiaries (the Partnership) as of December 31, 2015 and 2014, and the related consolidated statements of operations, partners' capital and parent company net investment, and cash flows of the Partnership and the Azure System Predecessor for the years ended December 31, 2015 and 2014, the period from November 15, 2013 to December 31, 2013, and the period from January 1, 2013 to November 14, 2013. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Azure Midstream Partners, LP as of December 31, 2015 and 2014 and the results of the operations and cash flows of Azure Midstream Partners, LP and the Azure System Predecessor for the years ended December 31, 2015 and 2014, the period from November 15, 2013 to December 31, 2013, and the period from January 1, 2013 to November 14, 2013, in conformity with U.S. generally accepted accounting principles.

As discussed in note 1 to the consolidated financial statements, effective November 15, 2013, the Partnership had a change in controlling ownership. As a result of this change in control, the financial information after November 15, 2013 is presented on a different cost basis than that for the periods before the acquisition and, therefore, is not comparable.

The accompanying consolidated financial statements have been prepared assuming that the Partnership will continue as a going concern. As discussed in note 3 to the consolidated financial statements, the Partnership anticipates being out of compliance with the requirements in the Credit Agreement during 2016, which would accelerate the maturity of the outstanding indebtedness making it currently due and payable. The Partnership does not have sufficient liquidity to meet the accelerated debt service requirements. This issue raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in note 3. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ KPMG LLP

Dallas, Texas

March 30, 2016

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

AZURE MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

(in thousands, except number of units)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,511	$ —
Accounts receivable, net	5,887	8,354
Accounts receivable—affiliates	5,148	76
Other current assets	339	435
Total current assets	18,885	8,865
Property, plant, and equipment, net	485,155	304,175
Intangible assets, net	59,583	—
Other assets	3,602	6,163
TOTAL ASSETS	$ 567,225	$ 319,203
LIABILITIES, PARTNERS’ CAPITAL AND PARENT COMPANY NET INVESTMENT		
Current liabilities:		
Accounts payable and accrued liabilities	$ 6,218	$ 5,630
Accounts payable—affiliates	96	96
Current portion of long-term debt allocated from the Azure Credit Agreement	—	10,104
Total current liabilities	6,314	15,830
Long-term liabilities:		
Long-term debt	231,735	181,871
Deferred income taxes	1,104	—
Other long-term liabilities	11,625	5,351
Total liabilities	250,778	203,052
Commitments and contingencies (Note 11)		
Partners' capital and parent company net investment:		
Common units (13,044,654 issued and outstanding as of December 31, 2015)	127,292	—
Subordinated units (8,724,545 issued and outstanding as of December 31, 2015)	114,807	—
General partner interest	5,137	—

Incentive distribution rights (100 issued and outstanding as of December 31, 2015)	69,211	—
Parent company net investment	—	116,151
Total partners’ capital and parent company net investment	316,447	116,151
TOTAL LIABILITIES, PARTNERS’ CAPITAL AND PARENT COMPANY NET INVESTMENT	$ 567,225	$ 319,203

See the accompanying notes to the consolidated financial statements.

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AZURE MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except unit and per unit data)

	Year Ended December 31, 2015	2014	Period from November 15, 2013 to December 31, 2013	Azure System Predecessor Period from January 1, 2013 to November 14, 2013
Operating Revenues:				
Natural gas, NGLs and condensate revenue	$ 19,938	$ 47,484	$ 4,728	$ 31,749
Natural gas, NGLs and condensate revenue—affiliates	1,782	4,000	806	—
Gathering, processing, transloading and other fee revenue	30,078	22,251	3,096	7,887
Gathering, processing, transloading and other fee revenue—affiliates	28,794	986	229	1,627
Total operating revenues	80,592	74,721	8,859	41,263
Operating Expenses:				
Cost of natural gas and NGLs	14,244	30,654	3,050	11,735
Cost of natural gas and NGLs—affiliates	4,164	7,388	1,455	9,319
Operation and maintenance	20,776	13,714	2,643	11,330
General and administrative	14,183	5,812	195	3,629
Depreciation and amortization expense	20,957	7,961	958	9,999
Impairments (Notes 2 and 8)	215,758	228	—	659
Total operating expenses	290,082	65,757	8,301	46,671
Operating income (loss)	(209,490)	8,964	558	(5,408)
Interest expense	11,333	15,149	1,855	3,167
Other (income) expense, net	916	422	—	(807)
Net loss before income tax expense	(221,739)	(6,607)	(1,297)	(7,768)
Income tax expense	686	213	26	118
Net loss	$ (222,425)	$ (6,820)	$ (1,323)	$ (7,886)
Net loss per unit and distributions declared:				
Net loss	$ (222,425)			
Less: Net loss attributable to the Azure System for the period January 1, 2015 to February 28, 2015	(3,543)			
Less: Net loss attributable to the General Partner for the ETG System for the period March 1, 2015 to June 30, 2015	(3,939)			
Net loss attributable to the Partnership	(214,943)			
Less: Net loss attributable to the General Partner	(4,148)			

Less: Net loss attributable to unvested phantom units		(3,572)
Net loss attributable to limited partners (1)	$	(207,223)
Net loss per limited partner common and subordinated units - basic and diluted (1)	$	(10.21)
Weighted average number of limited partner common units outstanding		11,577,680
Weighted average number of limited partner subordinated units outstanding		8,724,545
Distributions declared and paid per limited partner common and subordinated units (2)	$	1.11

(1) For the year ended December 31, 2015, net loss per unit has been presented for the period March 1, 2015 to December 31, 2015, the period in which units were outstanding for accounting purposes (see Note 1).

(2) On February 1, 2016, the Partnership announced a temporary suspension of the distribution for the quarterly period ended December 31, 2015.

See the accompanying notes to the consolidated financial statements.

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AZURE MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL AND

PARENT COMPANY NET INVESTMENT

(in thousands)

	General Partner Interest	Incentive Distribution Rights	Limited Partner Common Units	Subordinated Units	Parent Company Net Investment	Total
Balance at December 31, 2012	$ —	$ —	$ —	$ —	$ 189,547	$ 189,547
Azure System Predecessor net loss for the period	—	—	—	—	(7,886)	(7,886)
Azure System Predecessor net contribution from parent for the period	—	—	—	—	36,870	36,870
Balance at November 14, 2013	—	—	—	—	218,531	218,531
Elimination of Azure System parent company net investment	—	—	—	—	(218,531)	(218,531)
Azure System parent company net investment November 15, 2013	—	—	—	—	108,359	108,359
Azure System net loss for the period	—	—	—	—	(1,323)	(1,323)
Azure System net distribution from parent for the period	—	—	—	—	(8)	(8)
Balance December 31, 2013	—	—	—	—	107,028	107,028
Azure System net loss for the period	—	—	—	—	(6,820)	(6,820)
Azure System net contribution from parent for the period	—	—	—	—	15,943	15,943
Balance at December 31, 2014	—	—	—	—	116,151	116,151
	—	—	—	—	(3,543)	(3,543)

Azure System net loss for the period January 1, 2015 to February 28, 2015						
Parent company net contribution associated with the Legacy System	—	—	—	—	2,754	2,754
Deemed contribution associated with the Transactions	—	—	—	—	126,481	126,481
Issuance of IDR Units in connection with the Transactions	—	63,000	—	—	—	63,000
Distribution made in connection with the Transactions	—	—	—	—	(162,500)	(162,500)
Allocation of parent company net investment in connection with the Transactions	—	—	26,562	25,148	(51,710)	—
Acquisition of Azure Midstream Partners, LP	8,697	6,211	194,101	184,162	—	393,171
Parent company net contribution associated with the ETG System	—	—	—	—	2,278	2,278
Public offering of common units	1,012	—	48,537	—	—	49,549
Distributions to unitholders	(424)	—	(13,014)	(9,725)	—	(23,163)
Unit based compensation related to long-term incentive plan	—	—	932	—	—	932
Issuance of 255,319 common units in connection with the Contribution Agreement	—	—	3,000	—	—	3,000
Consideration paid in excess of net book value in connection with the Contribution Agreement	—	—	(6,809)	—	—	(6,809)
Deemed contribution associated with the Contribution Agreement	—	—	—	—	50,219	50,219
Transfer of ETG net assets to Azure	—	—	—	—	(76,191)	(76,191)

Midstream Partners, LP Net loss for the period March 1, 2015 to December 31, 2015	(4,148)	—	(126,017)	(84,778)	(3,939)	(218,882)
Balance at December 31, 2015	$ 5,137	$ 69,211	$ 127,292	$ 114,807	$ —	$ 316,447

See the accompanying notes to the consolidated financial statements.

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AZURE MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Azure System Predecessor
Period from	