American Midstream Partners, LP
Form 10-K
March 28, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
Or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-35257

AMERICAN MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	27-0855785
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2103 CityWest Boulevard Building #4, Suite 800 Houston, Texas	77042
(Address of principal executive offices)	(Zip code)

(346) 241-3400
(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 Partnership 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 o No x
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by checkmark 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 in, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2016, was $321,334,978. The aggregate market value was computed by reference to the closing price of the registrant's common units on the New York Stock Exchange on June 30, 2016.

There were 51,585,690 common units, 10,266,642 Series A Units, 8,792,205 Series C Units, and 2,333,333 Series D Units of American Midstream Partners, LP outstanding as of March 20, 2017. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

Documents Incorporated by Reference

None.

TABLE OF CONTENTS

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.
These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. These risks and uncertainties, many of which are beyond our control, include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" in this Annual Report on Form 10-K (the "Annual Report") as well as the following risks and uncertainties:

- our ability to integrate with JP Energy Partners LP (“JPE”) successfully after consummation of the JPE Merger (as defined herein) and to achieve anticipated benefits from the proposed transaction;
- our ability to generate sufficient cash from operations to pay distributions to unitholders;
- our ability to maintain compliance with financial covenants and ratios in our Credit Facility (as defined herein);
- dispositions of assets owned by us or JPE prior to the completion of the JPE Merger, which assets may have been material to us or JPE;
- our ability to timely and successfully identify, consummate and integrate our current and future acquisitions and complete strategic dispositions, including the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance;
- the timing and extent of changes in natural gas, crude oil, NGLs and other commodity prices, interest rates and demand for our services;
- our ability to access capital to fund growth, including new and amended credit facilities and access to the debt and equity markets, which will depend on general market conditions;
- severe weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- the level of creditworthiness of counterparties to transactions;
- the level and success of natural gas and crude oil drilling around our assets and our success in connecting natural gas and crude oil supplies to our gathering and processing systems;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- changes in laws and regulations, particularly with regard to taxes, safety, regulation of over-the-counter derivatives market and entities, and protection of the environment;
- our failure or our counterparties’ failure to perform on obligations under commodity derivative and financial derivative contracts;
- the performance of certain of our current and future projects and unconsolidated affiliates that we do not control;
- the demand for NGL products by the petrochemical, refining or other industries;
- our dependence on a relatively small number of customers for a significant portion of our gross margin;
- general economic, market and business conditions, including industry changes and the impact of consolidations and changes in competition;
- our ability to renew our gathering, processing, transportation and terminal contracts;
- our ability to successfully balance our purchases and sales of natural gas;

- the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects;
- our management's history and experience with certain aspects of our business and our ability to hire as well as retain qualified personnel to execute our business strategy;
- the cost and effectiveness of our remediation efforts with respect to the material weakness discussed in "Part II. Item 9A. Controls and Procedures";
- volatility in the price of our common units;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- the amount of collateral required to be posted from time to time in our transactions.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Item 1A. Risk Factors" in this Annual Report. Statements in this Annual Report speak as of the date of this report. Except as may be required by applicable securities laws, we undertake no obligation to publicly update or advise investors of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

As generally used in the energy industry and in this Annual Report, the identified terms have the following meanings:

Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
Bbl/d	Barrels per day.
Bcf	Billion cubic feet.
Btu	British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the natural gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
/d	Per day.
FERC	Federal Energy Regulatory Commission.
Fractionation	Process by which natural gas liquids are separated into individual components.
GAAP	Generally Accepted Accounting Principles in the United States of America
Gal	Gallons.
Mgal/d	Million gallons per day.
MBbl	Thousand barrels.
MMBbl	Million barrels.
MMBbl/d	Million barrels per day.
MMBtu	Million British thermal units.
Mcf	Thousand cubic feet.
MMcf	Million cubic feet.
MMcf/d	Million cubic feet per day.

NGL or NGLs	Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Tcf	Trillion cubic feet.
Throughput	The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

As used in this Annual Report, unless the context otherwise requires, "we," "us," "our," the "Partnership" and similar terms refer to American Midstream Partners LP, together with its consolidated subsidiaries. References in this Annual Report to our "General Partner" refer to American Midstream GP, LLC.

PART I
Item 1. Business

Overview

American Midstream Partners, LP (along with its consolidated subsidiaries, "we", "us," "our," or the "Partnership") is a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We provide critical midstream infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. Through our three reporting segments, (i) gathering and processing, (ii) transmission and (iii) terminals, we are engaged in the business of gathering, treating, processing, and transporting natural gas; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products.

Our primary assets are strategically located in some of the most prolific onshore and offshore producing regions and key demand markets in the United States. Our gathering and processing assets are primarily located in (i) the Permian Basin of West Texas, (ii) the Cotton Valley/Haynesville Shale of East Texas, (iii) the Eagle Ford Shale of South Texas, (iv) the Bakken Shale of North Dakota, and (v) offshore in the Gulf of Mexico. Our transmission and terminal assets are located in key demand markets in Alabama, Louisiana, Mississippi and, Tennessee, and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia.

We own or have ownership interests in more than 3,800 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 15 gathering systems, six interstate pipelines and eight intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 80 MMbl/d of crude oil and 200 MMcf/d of natural gas; and three marine terminal sites with approximately 2.4 MMBbls of above-ground aggregate storage capacity for petroleum products, distillates, chemicals and agricultural products.

A portion of our cash flow is derived from our investments in unconsolidated affiliates in our consolidated financial statements including a 49.7% operated interest in Destin Pipeline Company, L.L.C. (“Destin”), a natural gas pipeline; a 20.1% non-operated indirect interest in Class A units in the entities that own the Delta House floating production system platform and related pipeline infrastructure; a 16.7% non-operated interest in Tri-States NGL Pipeline, L.L.C. (“Tri-States”), an NGL pipeline; a 66.7% operated interest in Okeanos Gas Gathering Company, LLC (“Okeanos”); a 25.3% non-operated interest in Wilprise Pipeline Company, L.L.C. (“Wilprise”), an NGL pipeline; and a 66.7% non-operated interest in Main Pass Oil Gathering Company ("MPOG"), a crude oil gathering and processing system.

In our Gathering and Processing segment, we receive fee-based and fixed-margin compensation for gathering, processing, transporting and treating natural gas and crude oil. Where we provide processing services at the plants that we own or share an interest, or obtain processing services for our own account under our elective processing arrangements, we typically retain and sell a percentage of the residue natural gas and/or resulting NGLs under percent-of-proceeds ("POP") arrangements.

In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput volumes on our interstate and intrastate pipelines.

In our Terminals segment, we generally receive fee-based compensation under guaranteed firm storage contracts, throughput fees charged to our customers when their products are either received or disbursed, and other operational charges associated with ancillary services provided to our customers, such as excess throughput, steam heating and truck weighing.

Recent Developments

JPE Merger

On March 8, 2017, the Partnership completed the acquisition of JPE, an entity controlled by affiliates of ArcLight Capital Partners, LLC ("ArcLight"), in a unit-for-unit merger (the “JPE Merger”).” In connection with the transaction, each JPE common or subordinated unit held by investors not affiliated with ArcLight was converted into the right to receive 0.5775 of a Partnership common unit, and each JPE common or subordinated unit held by ArcLight affiliates was converted into the right to receive 0.5225 of a Partnership common unit. The Partnership issued a total of 20.2 million of the Partnership’s common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates. Unless stated otherwise, this Annual Report discusses the activities of the Partnership as of December 31, 2016. Any reference to the combined company considers activities subsequent to the JPE Merger and includes discussion regarding the Partnership and JPE (the "Combined Company").

As both the Partnership and JPE were controlled by ArcLight affiliates, the acquisition represents a transaction among entities under common control and will be accounted for as a common control transaction. Although the Partnership is the legal acquirer, JPE is considered to the acquirer for accounting purposes as ArcLight obtained control of JPE prior to it obtaining control of the Partnership on April 15, 2013. As a result, JPE will record the acquisition of the Partnership at ArcLight’s historical cost basis. The Partnership will file recast historical cost financial statements for the combined entity in May 2017.

JPE owns, operates and develops a diversified portfolio of midstream energy assets with three business segments (i) crude oil pipelines and storage, (ii) refined products terminals and storage and (iii) NGL distribution and sales, which together provide midstream infrastructure solutions for the growing supply of crude oil, refined products and NGLs, in the United States.

Third Amendment to Partnership Agreement

The Partnership also executed Amendment No. 3 to our Fifth Amended and Restated Partnership Agreement (as amended, the “Partnership Agreement”), which amends the distribution payment terms of the Partnership’s outstanding Series A Preferred Units to provide for the payment of Series A payment-in-kind (“PIK”) preferred units for the quarter (the “Series A Preferred Quarterly Distribution”) in which the JPE Merger is consummated (which is the quarter ended March 31, 2017) and thereafter equal to the quotient of (i) the greater of (a) $0.4125 and (b) the "Series A Distribution Amount", as such term is defined in the Partnership Agreement, divided by (ii) the Series A Adjusted Issue Price, as such term is defined in the Partnership Agreement. However, in our General Partner’s discretion, which determination shall be made prior to the record date for the relevant quarter, the Series A Preferred Quarterly Distribution may be paid as (x) an amount in cash up to the greater of (1) $0.4125 and (2) the Series A Distribution Amount, and (y) a number of Series A Preferred Units equal to the quotient of (a) the remainder of (i) the greater of (I) $0.4125 and (II) the Series A Distribution Amount less (ii) the amount of cash paid pursuant to clause (x), divided by (b) the Series A Adjusted Issue Price.

Second Amended and Restated Credit Agreement

On March 8, 2017, the Partnership and its operating company, American Midstream, LLC, along with other subsidiaries of the Partnership (collectively, the “Borrowers”) entered into a Second Amended and Restated Credit Agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders (the “Second Amended Credit Agreement”). By entering into the Second Amended Credit Agreement, the Partnership amended its existing credit facility to increase its borrowing capacity thereunder from $750 million to $900 million and to provide for an accordion feature that will permit, subject to the customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion. The $900 million in lending commitments under the Second Amended Credit Agreement includes a $30 million sublimit for borrowings by the Blackwater Borrower and a $100 million sublimit for standby letters of credit, which was increased in this Second Amended Credit Agreement from $50 million. The Second Amended Credit Agreement matures on September 5, 2019. The Second Amended Credit Agreement facilitates the joinder to the credit facility of certain surviving entities from the JPE Merger (the " JPE Entities") and adjusts certain covenants, representations and warranties under the credit facility to support the JPE Entities. All obligations under the Second Amended Credit Agreement and the guarantees of those obligations are secured, subject to certain exceptions, by a first-priority lien on and security interest in substantially all of the Borrowers’ assets and the assets of all, subject to certain exceptions, existing and future subsidiaries and all of the capital stock of the Partnership’s existing and future subsidiaries.

When we use the term “revolving credit facility” or “Credit Agreement,” we are referring to our First Amended and Restated Credit Facility and to our Second Amended and Restated Credit Facility, as the context may require.

8.50% Senior Notes

On December 28, 2016, the Partnership and American Midstream Finance Corporation, our wholly owned subsidiary (together with the Partnership, the “Issuers”) completed the issuance and sale of $300 million in aggregate principal amount of senior notes due 2021 (the "8.50% Senior Notes"). Wells Fargo Securities, LLC served as the representative of the initial purchasers, which included Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, LLC, Citigroup Global Markets Inc., SunTrust Robinson Humphrey, Inc., Natixis Securities Americas LLC, ABN AMRO Securities (USA) LLC, Capital One Securities, Inc., Deutsche Bank Securities Inc., BNP Paribas Securities Corp., BMO Capital Markets Corp., Santander Investment Securities Inc. and BBVA Securities Inc. The 8.50% Senior Notes rank equal in right of payment with all existing and future senior indebtedness of the Issuers, and senior in right of payment to any future subordinated indebtedness of the Issuers. The 8.50% Senior Notes were issued at par and provided net proceeds of approximately $294.0 million, after deducting the initial purchasers' discount of $6.0 million. This amount was deposited into escrow pending completion of the JPE Merger and is included in Restricted cash on the Partnership's consolidated balance sheet as of December 31, 2016. The Partnership also incurred $2.7 million of direct issuance costs resulting in net proceeds related to the 8.50% Senior Notes of $291.3 million. The notes were offered and sold to qualified institutional buyers in the United States pursuant to Rule 144A under the Securities Act, and to persons, other than U.S. persons, outside the United States pursuant to Regulation S under the Securities Act.

Upon the closing of the JPE Merger and the satisfaction of other related conditions the restricted cash was released from escrow on March 8, 2017. The Partnership used the net proceeds to repay and terminate JPE's revolving credit facility and to reduce borrowings under the Partnership’s Amended and Restated Credit Agreement (the "Credit Agreement").

Additional Delta House Investments

On April 25, 2016, American Midstream Delta House, LLC ("AMID Delta House"), our wholly-owned indirect subsidiary, entered into a unit purchase agreement with an ArcLight affiliate, pursuant to which AMID Delta House acquired 100% of the outstanding membership interests in D-Day Offshore Holdings, LLC ("D-Day"), which owned 912.4 Class A Units of Delta House FPS LLC ("Delta House FPS") and 53.5 Class A Units of Delta House Oil and Gas Lateral LLC ("Delta House Lateral") in exchange for approximately $9.9 million in cash funded with additional borrowings under the Partnership’s Credit Agreement. Delta House is a semisubmersible floating production system platform with associated crude oil and natural gas export pipelines, located in the Mississippi Canyon region of the deepwater Gulf of Mexico. Delta House FPS owns the floating production system and Delta House Lateral owns the associated crude oil and natural gas export pipelines. When we refer to "Delta House" we are referring to our investment in Delta House FPS and Delta House Lateral.

On October 31, 2016, D-Day acquired an additional 6.2% direct interest in Delta House by purchasing additional Class A Units in Delta House FPS and Delta House Lateral from unrelated parties for approximately $48.8 million, which was funded with net proceeds of $34.5 million from the issuance of 2,333,333 Series D convertible preferred units ("Series D Units") to an ArcLight affiliate, plus $14.3 million in cash funded with borrowings under our Credit Agreement. The Series D Units were issued at $15.00 per unit, less a 1.5% closing fee, and if any Series D Units remain outstanding on June 30, 2017, the Partnership will issue a warrant to purchase up to 700,000 common units representing limited partnership interests in the Partnership (“common units”) with an exercise price of $22.00 per common unit (the "Series D Warrants"). Magnolia Infrastructure Holdings, LLC (an affiliate of ArcLight) holds the Series D Units and participates in the related distributions which are to be made in cash. The Series D Units were issued, and the Series D Warrants, if issued, will be issued, in a private placement in reliance upon an exemption from the registration requirements of the Securities Act pursuant to Section 4(a)(2) thereof and the safe harbor provided by Rule 506 of Regulation D promulgated thereunder.

The investment in D-Day, together with our 26.3% interest in Pinto Offshore Holdings, LLC, an entity that owns a 49.0% non-operated interest in Delta House Class A Units, results in the Partnership holding a combined 20.1% non-operated indirect and direct interest in Delta House. Our interest in Delta House includes a 20.1% interest in Class A Units of Delta House FPS.The Class A Units in Delta House FPS are currently entitled to receive 100% of the distributions from Delta House FPS until a certain payout threshold is met. Once the payout threshold is met, approximately 7% of distributions from Delta House FPS will be paid to the Class B membership interests in Delta House FPS. It is currently estimated that the payout threshold on the Class A Units will be met in the year 2020.

3.77% Senior Notes

On September 30, 2016, Midla Financing, LLC (“Midla Financing”), American Midstream (Midla), LLC (“Midla”) and Mid Louisiana Gas Transmission LLC (“MLGT” and, together with Midla, the “Note Guarantors”), entered into a Note Purchase and Guaranty Agreement (the “3.77% Senior Note Purchase Agreement”) with Massachusetts Mutual Life Insurance Company and MassMutual Asia Limited (the “Purchasers”) whereby Midla Financing sold $60.0 million in aggregate principal amount of Senior Notes to the Purchasers, which bear interest at an annual rate of 3.77% to be paid quarterly (the "3.77% Senior Notes"). Principal and interest on the 3.77% Senior Notes is payable in installments on the last business day of each quarter beginning June 30, 2017 with the remaining balance payable in full on June 30, 2031. The average quarterly principal payment is approximately $1.1 million. The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million after deducting related issuance costs of $2.3 million. Morgan Stanley Senior Funding, Inc. served as the placement agent. The 3.77% Senior Notes were offered and sold in a private placement in reliance upon an exemption from the registration requirements of the Securities Act of 1933 pursuant to Section 4(a)(2) thereof and the safe harbor provided by Rule 506 of Regulation D promulgated thereunder.

Net proceeds from the 3.77% Senior Notes are restricted and will be used to fund the retirement of Midla's existing 1920's pipeline, project costs incurred in connection with the construction of a new replacement pipeline from Winnsboro, Louisiana to Natchez, Mississippi (the "Midla-Natchez Line"), the move of our Baton Rouge operations to the MLGT system, and the reconfiguration of the DeSiard compression system and all related ancillary facilities. These proceeds can also be used to pay costs incurred in connection with the issuance of the 3.77% Senior Notes, and for general corporate purposes of Midla Financing. As of December 31, 2016, Restricted cash includes $24.5 million from the issuance of the 3.77% Senior Notes. Construction commenced on the Midla-Natchez Line in the second quarter of 2016 with service expected to begin within the first six months of 2017.

Acquisition of interests in Gulf of Mexico midstream assets

On April 15, 2016, American Panther, LLC ("American Panther"), a 60%-owned subsidiary of the Partnership, acquired approximately 200 miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines ("Gulf of Mexico Pipeline") from Chevron Pipeline Company and Chevron Midstream Pipeline, LLC for approximately $2.7 million in cash and the assumption of certain asset retirement obligations. The Partnership controls American Panther and therefore consolidates it for financial reporting purposes.

The Gulf of Mexico Pipeline acquisition was accounted for using the acquisition method of accounting and as a result, the purchase price was allocated to the assets acquired and liabilities assumed based on their respective estimated fair values as of the acquisition date. The purchase price allocation included $16.6 million in pipelines, $0.4 million in land, $14.3 million in asset retirement obligations and $1.8 million in noncontrolling interests.

Emerald Transactions

On April 25, 2016 and April 27, 2016, American Midstream Emerald, LLC ("Emerald"), a wholly-owned indirect subsidiary of the Partnership, entered into two purchase and sale agreements with an ArcLight affiliate, for the purchase of membership interests in certain entities (together, the "Emerald Transactions").

On April 25, 2016, Emerald entered into the first purchase and sale agreement for the purchase of membership interests in entities that own and operate natural gas pipeline systems and NGL pipelines in and around Louisiana, Alabama, Mississippi, and the Gulf of Mexico (the "Pipeline Purchase Agreement"). Pursuant to the Pipeline Purchase Agreement, Emerald acquired (i) 49.7% of the issued and outstanding membership interests of Destin, (ii) 16.7% of the issued and outstanding membership interests of Tri-States and (iii) 25.3% of the issued and outstanding membership interests of Wilprise, in exchange for approximately $183.6 million (the "Pipeline Transaction").

On April 27, 2016, Emerald entered into the second purchase and sale agreement for the purchase of 66.7% of the issued and outstanding membership interests of Okeanos, in exchange for a cash purchase price of approximately $27.4 million. The Okeanos pipeline is a 100-mile natural gas gathering system located in the Gulf of Mexico with a total capacity of 1.0 Bcf/d.

The Partnership funded the aggregate purchase price for the Emerald Transactions with the issuance of 8,571,429 Series C convertible preferred units (the "Series C Units") representing limited partnership interests in the Partnership and a warrant (the "Series C Warrant") to purchase up to 800,000 common units at an exercise price of $7.25 per common unit amounting to a combined value of approximately $120.0 million, plus additional borrowings of $91.0 million under our Credit Agreement. ArcLight affiliates hold and participate in distributions on our Series C Units with such distributions being made in paid-in-kind Series C Units, cash or a combination thereof at the election of the Board of Directors of our General Partner. Magnolia Infrastructure Holdings, LLC, an ArcLight affiliate, holds the Series C Units. The Series C Units and the Series C Warrant were both issued in a private placement in reliance upon an exemption from the registration requirements of the Securities Act pursuant to Section 4(a)(2) thereof and the safe harbor provided by Rule 506 of Regulation D promulgated thereunder.

Because our interests in the entities underlying the Emerald Transactions were previously owned by an ArcLight affiliate, we accounted for our investments at our affiliate’s historical cost basis of $212.0 million, and recorded them in Investment in unconsolidated affiliates in our consolidated balance sheet, and as an investing activity of $100.9 million within the consolidated statement of cash flows. The amount by which the affiliate's historical basis exceeded total consideration was $1.0 million and is recorded as a contribution from our General Partner in the consolidated statements of changes in partners’ capital and noncontrolling interests.

Market Conditions

Average daily prices for New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") crude oil ranged from a high of $54.45 per barrel to a low of $26.21 per barrel from January 1, 2016 through March 13, 2017. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.80 per MMBtu to a low of $1.49 per MMBtu from January 1, 2016 through March 13, 2017. We are unable to predict future movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices do not continue the current upward trend from 2016 to 2017, this could lead to reduced profitability and may impact our liquidity and compliance with the financial covenants in our Credit Agreement. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets, as well as the reduction or elimination of distributions to our unitholders.

Business Strategies

Our principal business objective is to increase our quarterly cash flows over time while ensuring the long-term stability of our business. We expect to achieve this objective by focusing on the following strategies:

Utilize our strategically located and integrated assets to maximize value for our customers. We own and operate a portfolio of midstream assets strategically located in some of the most prolific natural gas and crude oil producing regions and key demand markets in the United States and offshore in the Gulf of Mexico. Through our diversified and integrated asset base, we provide critical infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets while allowing us to generate revenue and service the same energy molecules at various stages along the midstream value chain.

Enhance existing assets and realize operating efficiencies. We intend to enhance the profitability of our assets by increasing utilization, realizing operating efficiencies and providing additional midstream services desired by our customers. We continually seek to attract new volumes from existing and new customers through superior customer service and asset optimization. In addition, we expect to be able to provide additional midstream services to our customers by cross- selling complementary services. For example, we intend to leverage our recently acquired crude oil and NGL trucking capabilities across our onshore gathering and processing footprint and expand our service offering in the Permian Basin and Cotton Valley/Haynesville Shale. We can accommodate additional volumes at minimal incremental cost, which provides highly attractive economics.

Capitalize on organic growth opportunities. We continually seek to identify and evaluate economically attractive organic expansion opportunities that leverage our asset footprint and strategic relationships with our customers. These organic projects include new interconnects, repurposing underutilized assets and adding additional capacity to meet increased demand from our customers. For example, we are evaluating the expansion of our existing Harvey terminal by adding 1.35 MMBbls of incremental storage capacity, additional rail capacity and a second deep water ship berth. There has been steady demand for storage capacity in the Port of New Orleans, and the Harvey site is currently 98% utilized and continues to attract interest for long-term storage.

Pursue accretive acquisitions. We plan to pursue accretive acquisitions of complementary midstream assets that will allow us to increase market share and density in our core operating areas and realize operational efficiencies and commercial synergies. Future acquisition opportunities may include bolt-on acquisitions within our asset footprint, consolidation of third party interests in our joint ventures and strategic acquisitions. Our partnership with ArcLight may present us with future drop-down opportunities and the ability to jointly pursue third party acquisitions that may not otherwise be feasible on a stand-alone basis.

Maintain focus on stable, fee-based and fixed-margin cash flow with minimal direct exposure to commodity prices. We seek to minimize our direct commodity price exposure and maintain stable cash flow by generating a substantial portion of our total gross margin pursuant to fee-based and fixed-margin contracts. We have been successful executing on this strategy and have increased the percentage of gross margin generated from fee-based and fixed-margin contracts from 74.4% to 88.9% for the fiscal years ended December 31, 2014 and 2016, respectively.

Maintain a conservative and flexible capital structure. We plan to pursue a disciplined financial policy and maintain a conservative capital structure to allow us to pursue additional organic growth projects and acquisitions, with a conservative mix of debt and equity, even in challenging market environments. We expect our increased scale and diversification and improved financial position resulting from the JPE Merger will enhance our access to sources of capital.

Competitive Strengths. We believe we are well-positioned to successfully execute our strategy because of the following competitive strengths:

Stable and predictable cash flows supported by fee-based and fixed-margin contracts. Substantially all of our transmission and terminal assets are contracted on a firm transportation or take-or-pay basis and a majority of our offshore assets are contracted under long-term, life-of-lease dedications. We believe that the nature of our contracts minimizes our direct commodity price exposure and enhances the stability of our business and the predictability of our financial performance.

Diversified and strategically located portfolio of midstream assets. Our assets are diversified geographically and by business line, which contribute to the stability of our cash flows. We operate throughout many of the most prolific crude oil and natural gas producing regions in the United States and offshore Gulf of Mexico. We have access to multiple sources of crude oil, natural gas and liquids and are in close proximity to various interstate and intrastate pipelines as well as utility, industrial and other commercial end users. Our diverse and creditworthy customer base includes producers, refiners and marketers including ConocoPhillips Co., Royal Dutch Shell plc, BP P.L.C., Chevron Corporation, Exxon Mobil Corp., LLOG Exploration Company, L.L.C. and Monsanto Company.

Significant scale and capability. As of December 31, 2016, after giving effect to the JPE Merger, we have $2.3 billion in total assets across the midstream value chain providing onshore and offshore crude oil and natural gas gathering, processing, transmission and storage as well as hydrocarbon and refined product terminal assets and NGL fractionation, distribution and sales. Following the closing of the JPE Merger, we own or have an ownership interest in approximately 4,000 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 16 gathering systems, six interstate pipelines and nine intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semi-submersible floating production system with nameplate processing capacity of 80 MBbl/d of crude oil and 200 MMcf/d of natural gas; six terminal sites with approximately 6.7 MMBbls of above-ground storage capacity; and a fleet of 97 crude oil gathering and LPG transport trucks. In addition, we have the third largest cylinder exchange business in the United States. We believe our size, scale and capabilities enhance our ability to serve our customers and provide financial flexibility and an increased ability to access the capital markets.

Strategically located offshore position with high barriers to entry. We have a substantial footprint in the deepwater Gulf of Mexico with our ownership interest in the Delta House platform and associated assets. This state-of-the-art floating, production and storage facility is located in one of the most active parts of the deep-water Gulf of Mexico and we have well-established relationships and long-term agreements with key participants along the entire value chain in the region. We believe producers in the areas of the Gulf of Mexico in which we operate are motivated to connect their production to our existing pipelines as construction of new pipelines is often not feasible due to cost and timing considerations. In addition, we have acquired additional strategic assets that provide us with substantial operational flexibility including multiple delivery and offload points as we move hydrocarbons from source to market, allowing us to provide a valuable and differentiated service to our customers.

Relationship with ArcLight. Our relationship with ArcLight provides us with access to ArcLight's extensive operational and commercial expertise. ArcLight controls High Point Infrastructure Partners, LLC ("HPIP"), the majority owner of our general partner, owns 49.3% of our limited partner units and 100% of the IDRs. We believe that ArcLight is economically incentivized to promote and support our business plan and to pursue projects that enhance the overall value of our business.

Experienced management and operational teams. Our executive management team has an average of approximately 18 years of experience in the midstream energy industry. The team possesses a comprehensive skill set to support our business and execute our business strategy through asset optimization, accretive development projects and acquisitions.

Our Assets

Our primary assets are strategically located in some of the most prolific onshore and offshore producing regions and key demand markets in the United States. Our gathering and processing assets are primarily located in (i) the Permian Basin of West Texas, (ii) the Cotton Valley/Haynesville Shale of East Texas, (iii) the Eagle Ford Shale of South Texas, (iv) the Bakken Shale of North Dakota, and (v) offshore in the Gulf of Mexico. Our transmission and terminal assets are located in key demand markets in Alabama, Louisiana, Mississippi and Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia.

We own or have ownership interests in more than 3,800 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 15 gathering systems; six interstate pipeline; eight intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 80 MMBbl/d of crude oil and 200 MMcf/d of natural gas; and three marine terminal sites with approximately 2.4 MMBbls of above-ground aggregate storage capacity for petroleum products, distillates, chemicals and agricultural products.

A portion of our cash flow is derived from our investments in unconsolidated affiliates including a 49.7% operated interest in Destin, a natural gas pipeline; a 20.1% non-operated indirect interest in Class A units of Delta House, which is a floating production system platform and related pipeline infrastructure; a 16.7% non-operated interest in Tri-States, an NGL pipeline; a 66.7% operated interest in Okeanos, a natural gas pipeline; a 25.3% non-operated interest in Wilprise, an NGL pipeline; and a 66.7% non-operated interest in MPOG, a crude oil gathering and processing system. We organize our operations into three business segments: i) Gathering and Processing; ii) Transmission; and iii) Terminals.

Gathering and Processing Segment

General

Our Gathering and Processing segment consists of midstream natural gas systems that provide the following services to our customers:

- gathering;
- compression;
- treating;
- processing;
- fractionating;
- transportation; and
- sales of natural gas, crude oil, NGLs and condensate.

Our Gathering and Processing assets are located in Alabama, Louisiana, Mississippi, North Dakota and Texas and in shallow state and federal waters in the Gulf of Mexico off the coast of Louisiana and are positioned in areas with opportunities for organic growth. We continually seek new sources of raw natural gas and crude oil supply to maintain and increase the throughput volume on our gathering systems and through our processing plants.

We generally derive revenue in our Gathering and Processing segment from fee-based, fixed-margin and POP arrangements, for our producer and supplier customers and our own account. For the year ended December 31, 2016, our fee-based, fixed-margin arrangements and our POP arrangements accounted for approximately 80.6% and 19.4%, respectively, of our segment gross margin for the Gathering and Processing segment. For the year ended December 31, 2015, our fee-based, fixed-margin arrangements and our POP arrangements accounted for approximately 77.3% and 22.7%, respectively, of our segment gross margin for the Gathering and Processing segment.

The following table provides information regarding our Gathering and Processing segment assets for the years ended December 31, 2016 and 2015.

	Approximate Gathering System (Miles)	Approximate Design Capacity (MMcf/d) (MBbl/d)	Compression (Horsepower)	Number of Plants and Fractionators	Approximate Average Throughput (MMcf/d) (MBbl/d) Years Ended December 31,	
					2016	2015
Gathering and Processing						
Lavaca	203	218	28,175	—	114.0	119.1
Magnolia	118	122	4,690	—	25.4	27.1
Longview	620	50	19,980	3	15.1	17.2
Chapel Hill	90	20	2,540	2	14.0	14.6
Yellow Rose	47	40	3,256	1	4.3	4.2
Bakken (1)	43	40	—	—	7.2	2.2

Chatom (2)	24	25	3,456	2	6.3	5.9
Bazor Ridge	169	22	6,287	1	5.6	7.6
Glade Crossing	—	10	—	1	—	—
American Panther	200	502	—	—	86.6	—
Other (3)	268	346	11,062	2	122.4	142.5
Total	1,782	1,395	79,446	12	400.9	340.4

(1) Average throughput for the year ended December 31, 2015 only reflects the months of October 2015 through December 2015.
(2) We have included approximate average throughput at 100% for the Chatom System. For both periods ending December 31, 2016 and 2015, we owned 92.2% interest in the Chatom System.
(3) Other primarily includes our Gloria, Lafitte, Quivira, Burns Point, and Offshore Texas systems.

Lavaca System

The Lavaca System consists of 203 miles of high and low-pressure pipelines ranging from four to 12 inches in diameter with 24,960 horsepower of leased compression, 3,215 horsepower of owned compression and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas. The Lavaca System currently has a design capacity of approximately 218 MMcf/d. Natural gas production gathered by the system is compressed and delivered to a third-party for processing or redelivered to producers for gas lift.

Magnolia System

The Magnolia gathering system is a Section 311 intrastate pipeline that gathers coal-bed methane in Tuscaloosa, Greene, Bibb, Chilton and Hale counties of Alabama and delivers this natural gas to an interconnect with the Transcontinental Gas Pipe Line Co. pipeline system ("Transco Pipeline System"), an interstate pipeline owned by The Williams Companies, Inc. The Magnolia System consists of approximately 118 miles of pipeline with small-diameter gathering lines and trunk lines ranging from six to 24 inches in diameter and four compressor stations with 4,690 horsepower.

Longview System

The Longview gathering and processing system consists of approximately 620 miles of high and low pressure gathering lines with diameters ranging from two to twenty inches with a combined compression capacity of 19,980 horsepower. Our Longview System also contains two cryogenic processing plants with a design capacity of approximately 50 MMcf/d, one fractionation unit with 8,500 Bbls/d of capacity, product storage tanks, and truck racks to receive off-spec NGLs and condensate. The Longview System is located near Longview in Gregg County, Texas. Located adjacent to the Longview System is a rail facility designed to receive and deliver NGLs and condensate which commenced operations in the first quarter of 2016.

Chapel Hill System

The Chapel Hill gathering and processing system consists of approximately 90 miles of gathering lines with a combined compression capacity of 2,540 horsepower. Our Chapel Hill System also contains a cryogenic processing plant with a design capacity of approximately 20 MMcf/d, one fractionation unit with 1,250 Bbls/d of capacity, product storage tanks, and truck racks to deliver propane, butane, and natural gasoline. The Chapel Hill System is located near Tyler in Smith County, Texas.

Yellow Rose System

The Yellow Rose gathering and processing system consists of approximately 47 miles of high and low pressure pipelines, a rich-gas gathering system and a 40 MMcf/d cryogenic processing plant, with pipeline takeaway for residue gas and liquids. The Yellow Rose System is located in the Permian Basin in Martin County, Texas.

Bakken System

The Bakken crude oil gathering pipeline system consists of a 43 mile pipeline with capacity to transport up to approximately 40,000 Bbls/d of crude oil to the Tesoro Logistics pipeline located Northeast of Watford City, North Dakota and a planned interconnect with the Energy Transfer Dakota Access Pipeline. The system, which commenced operations in October 2015, provides producers in the area with access to refinery, rail and pipeline markets. The system also has the capability to receive volumes through its truck rack, which also commenced operations in November 2015.

Chatom System

The Chatom System consists of a 25 MMcf/d refrigeration processing plant, a 1,600 Bbl/d fractionation unit, a 160 long-ton per day sulfur recovery unit, and a 24 mile gas gathering system and compression capacity of 3,456 horsepower. The system is located in Washington County, Alabama, approximately 15 miles from our Bazor Ridge processing plant in Wayne County, Mississippi. The Chatom System gathers natural gas from onshore crude oil and natural gas wells in the Norphlet and Smackover formations in Alabama and Mississippi. Chatom also has a truck rack and the capability to receive and fractionate NGLs.

Bazor Ridge System

The Bazor Ridge gathering and processing system consists of approximately 169 miles of pipeline, with diameters ranging from three to eight inches, and three compressor stations with a combined compression capacity of 1,069 horsepower. Our Bazor Ridge System is located in Jasper, Clarke, Wayne and Greene counties of Mississippi. The Bazor Ridge System also contains an idled sour natural gas treating and cryogenic processing plant located in Wayne County, Mississippi, with a design capacity of approximately 22 MMcf/d as well as four inlets and one discharge compressor with approximately 5,218 of combined horsepower. The natural gas supply for our Bazor Ridge System is derived primarily from rich natural gas produced from crude oil wells targeting the mature Upper Smackover formation. As of December 2016, the Bazor Ridge facility is exclusively used as a central gathering and compression facility and processing was re-routed to the Chatom System.

Glade Crossing

The Glade Crossing processing facility consists of a refrigeration unit, amine plant, and dehydration equipment with a design capacity of 10 MMcf/d. The facility is located near Laurel in Jones County, Mississippi.

American Panther System

The American Panther system is comprised of approximately 200 miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines. The system is located in Southern Louisiana and the Gulf of Mexico and has a natural gas design capacity of 475.0 MMcf/d and crude oil and saltwater capacity of 27.0 MBbl/d.

Other Gathering and Processing Systems

Gloria and Lafitte systems. The Gloria gathering system provides gathering and compression services through our assets, as well as processing services through our elective processing arrangements. The Gloria System is located in Lafourche, Jefferson, Plaquemines, St. Charles and St. Bernard parishes of Louisiana and consists of approximately 138 miles of pipeline, with diameters ranging from three to 16 inches, and four compressors with a combined size of 2,962 horsepower. The Gloria System may experience excess volumes from our Lafitte system. The Lafitte gathering system consists of approximately 40 miles of gathering pipeline, with diameters ranging from four to 12 inches and a design capacity of approximately 71 MMcf/d. The Lafitte System originates onshore in southern Louisiana and terminates in Plaquemines Parish, Louisiana, at the Alliance Refinery owned by Phillips 66. We are the sole supplier of natural gas to the Alliance Refinery through our Lafitte and Gloria systems. We supply natural gas to the Alliance Refinery pursuant to a long-term contract that expires in 2026.

Quivira and Burns Point Systems. The Quivira gathering system consists of approximately 34 miles of pipeline, with a 12-inch diameter mainline and several laterals ranging in diameter from six to eight inches. The system originates offshore of Iberia and St. Mary parishes of Louisiana in Eugene Island Block 24 and terminates onshore in St. Mary Parish, Louisiana, at a connection with the Burns Point Plant, a cryogenic processing plant with a design capacity of 165 MMcf/d that is jointly owned by us and the plant operator, Enterprise Gas Processing, LLC ("Enterprise"). We hold a 50% undivided, non-operated interest in the Burns Point Plant. We acquired an interest in the asset group and not in a legal entity. We and Enterprise are proportionately liable for the liabilities. Outside of the rights and responsibilities of the operator, we and Enterprise have equal rights and obligations to the assets. Significant non-capital and maintenance capital expenditures, plant expansions and significant plant dispositions require the approval of both owners.

Offshore Texas System. The Offshore Texas System consists of the GIGS and Brazos systems, which have approximately 56 miles of pipeline with diameters ranging from six to 16 inches and a design capacity of approximately 100 MMcf/d. The Offshore Texas System is in a position to provide gathering and dehydration services to natural gas producers in the shallow waters of the Gulf of Mexico offshore Texas. As of December 31, 2016, the offshore pipe on both systems has been abandoned, and the onshore pipe is out of service.

Mesquite

We own a 48.4% non-operated interest in Mesquite, a joint venture with EnLink Midstream located near Midland, Texas. The Mesquite facility includes a rail terminal, 5,000 Bbl/d condensate stabilization facility and 5,000 Bbl/d fractionation unit that facilitates the receipt, treatment and sale of off-spec condensate and NGLs via pipeline, truck and rail.

Customers and Contracts

For the year ended December 31, 2016, our Gathering and Processing segment derived 11% of its revenue from ConocoPhillips. For the year ended December 31, 2015, our Gathering and Processing segment derived 12% of its revenue from both ConocoPhillips and Penn Virginia, respectively. With respect to our Gathering and Processing segment, substantially all of the natural gas produced on our Lavaca System is gathered for Penn Virginia Corporation. Our contract with Penn Virginia Corporation expires in 2039. On our Gloria and Lafitte systems, we have a buy/sell agreement whereby most of the natural gas is sold to ConocoPhillips for use at the Alliance Refinery in Plaquemines Parish, Louisiana, under a contract that expires in 2026. Standard & Poor's Financial Services LLC ("Standard & Poor's") rated ConocoPhillips as "A-" and Moody's Investor Service ("Moody's") rated Penn Virginia as "D-PD" during 2016.

Transmission Segment

General

Our Transmission segment is comprised of interstate and intrastate pipelines that transport natural gas from interconnection points on other large pipelines or production points to customers, such as local distribution companies ("LDCs"), electric utilities, direct-served industrial complexes, or to interconnects on other pipelines. Certain of our pipelines are subject to regulation by FERC and by state regulators. In this segment, we often enter into firm transportation contracts with our shipper customers to transport natural gas sourced from large interstate or intrastate pipelines. Our Transmission segment assets are located in multiple parishes in Louisiana, including onshore and offshore producing regions around southeast Louisiana, and multiple counties in Mississippi, Alabama and Tennessee.

The following table provides information regarding our Transmission segment assets for the years ended December 31, 2016 and 2015.

	Approximate Transmission System (Miles)	Jurisdiction	Compression (Horsepower)	Approximate Design Capacity (MMcf/d)	Approximate Average Throughput (MMcf/d) Years Ended December 31,	
					2016	2015
Transmission						
High Point	574	Intrastate	—	1,120	318.7	371.6
Midla/MLGT (1)	424	Interstate/Intrastate	2,905	—	145.3	139.7
AlaTenn/Bamagas/TriGas	346	Interstate/Intrastate	3,665	710	204.7	182.7
Chalmette	39	Intrastate	—	125	14.6	14.6
Total	1,383		6,570	1,955	683.3	708.6

(1) We filed for abandonment in December 2016.

High Point System

The High Point System consists of approximately 574 miles of natural gas and liquids pipeline assets located in southeast Louisiana and the shallow water and deep shelf Gulf of Mexico. The High Point System gathers natural gas from both onshore and offshore producing regions around southeast Louisiana. The onshore footprint is Plaquemines and St. Bernard Parish, Louisiana. The offshore footprint consists of the following federal Gulf of Mexico zones: Mississippi Canyon, Viosca Knoll, West Delta, Main Pass, South Pass and Breton Sound. Natural gas is collected at more than 63 receipt points that connect to hundreds of wells targeting various geological zones in water depths up to 1,000 feet, with an emphasis on crude oil and liquids-rich reservoirs. The High Point System is comprised of

FERC-regulated transmission assets and non-jurisdictional gathering assets, both of which accept natural gas from well production and interconnected pipeline systems. The High Point System delivers the natural gas to the Toca Gas Processing Plant, which is operated by Enterprise, where the products are processed and the residue gas is sent to an unaffiliated interstate system owned by Kinder Morgan Energy Partners.

Midla and MLGT Systems

Our Midla System is an interstate natural gas pipeline with approximately 355 miles of pipeline linking the Monroe Natural Gas Field in northern Louisiana and interconnections with the Transco Pipeline System to customers in Mississippi and Louisiana.

The northern portion of the system, including the T-32 lateral, consists of approximately four miles of high-pressure, 12-inch-diameter pipeline. Natural gas on the northern end of the Midla System is delivered to two power plants operated by Entergy by way of the T-32 lateral and the CLECO Sterlington plant by way of the Sterlington lateral. In addition, the new Angus Chemical market will be connected on the T-32 system in the first half of 2017, increasing the load by approximately 7,000 mcf/d.

The mainline consists of approximately 170 miles of low-pressure, 22-inch-diameter pipeline with laterals ranging in diameter from two to 16 inches. This section of the Midla System primarily serves small local distribution companies or LDCs under firm transportation contracts that automatically renew on a year-to-year basis. Substantially all of these contracts are at the maximum rates allowed under Midla's FERC tariff.

The southern portion of the system, including associated laterals, consists of approximately two miles of high and low-pressure, 12-inch-diameter pipeline. This section of the system primarily serves industrial and LDC customers in southern Louisiana.

The MLGT System is an intrastate transmission system that sources natural gas from interconnects with the FGT Pipeline system, the Tetco Pipeline system, the Transco Pipeline system and the Gulf South Pipeline to various markets including a Baton Rouge, Louisiana refinery owned and operated by ExxonMobil Corporation, several other industrial customers and Entergy. Our MLGT System is comprised of approximately 65 miles of pipeline with diameters ranging from three to 14 inches. The MLGT System is connected to six receipt and 28 delivery points.

On April 16, 2015, the FERC approved the Midla Agreement between Midla and its customers allowing Midla to retire the existing 1920's pipeline and replace the existing natural gas service with the new Midla-Natchez Line to serve existing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service. On June 29, 2015, the Partnership filed for authorization to construct the Midla-Natchez pipeline with the FERC, which was approved on December 17, 2015. Construction commenced in the second quarter of 2016 with service expected to begin in the first half of 2017. Under the Midla Agreement, Midla has executed long-term agreements seeking to recover its investment in the Midla-Natchez Line.

AlaTenn/Bamagas/Trigas

AlaTenn System. The AlaTenn System is a FERC-regulated interstate natural gas pipeline that interconnects with three major interstate pipelines and travels west to east delivering natural gas to industrial customers in northwestern Alabama. In addition, the AlaTenn System serves numerous loads via North Alabama Gas District, as well as Alabama municipalities such as the cities of Athens, Hartselle, Sheffield, and Huntsville. Our AlaTenn System has a design capacity of approximately 200 MMcf/d and is comprised of approximately 294 miles of pipeline with diameters ranging from three to 16 inches and includes two compressor stations with combined capacity of 3,665 horsepower. The AlaTenn System is connected to over 60 active delivery and four receipt points, including two interconnects with the Tennessee Gas Pipeline ("TGP") system, an interstate pipeline owned by Kinder Morgan, the Tetco Pipeline system, an interstate pipeline owned by Spectra Energy Transmission, LLC, and the Columbia Gulf Pipeline system, an interstate pipeline owned by NiSource Gas Transmission and Storage. In mid-2017, AlaTenn will connect with the Southern Natural Gas system, an interstate pipeline owned by Kinder Morgan, which will provide access to new markets.

Bamagas System. Our Bamagas System is a Hinshaw intrastate natural gas pipeline that travels west to east from an interconnection point with TGP in Colbert County, Alabama, to two power plants in Morgan County, Alabama. The Bamagas System consists of 52 miles of high-pressure, 30-inch pipeline with a design capacity of approximately

450 MMcf/d. Currently, 100% of the throughput on this system is contracted under long-term firm transportation agreements.

Trigas System. Our Trigas System is located in three counties in northwestern Alabama and has approximate design capacity of 60 MMcf/d. Our Trigas System currently serves primarily industrial loads.

Chalmette System. The Chalmette System is located in St. Bernard Parish, Louisiana. The approximate design capacity for the Chalmette System is 125 MMcf/d.

Customers

In our Transmission segment, we contract with LDCs, electric utilities, or direct-served industrial complexes, or to interconnections on other large pipelines, to provide firm and interruptible transportation services.

For our Midla and AlaTenn systems, and a portion of our High Point systems, which are interstate natural gas pipelines, the maximum and minimum rates for services are governed by each individual system's FERC-approved tariff. In some cases, with FERC approval, we can have rates or certain other terms that are different from those generally provided for in the FERC tariff. For our Bamagas and MLGT systems, which are intrastate pipelines providing interstate services under the Hinshaw exemption of the Natural Gas Act ("NGA"), we negotiate service rates with each of our shipper customers.

For our High Point systems, we have interruptible transportation contracts in place with various customers operating in both onshore and offshore producing regions around southeast Louisiana. During 2015, we converted a fixed-margin arrangement on our MLGT System to an interruptible transportation contract, which has reduced the amount of natural gas that we purchase and sell.

Superior Natural Gas Corporation and ConocoPhillips are the two largest purchasers of natural gas and transmission capacity in our Transmission segment and accounted for approximately 14% and 13%, respectively, of our segment revenue for the year ended December 31, 2016. For the year ended December 31, 2015, Superior Natural Gas Corporation and Enbridge Marketing (US) L.P. accounted for approximately 19% and 16%, respectively, of our segment revenue. The majority of our firm and interruptible transportation contracts in the Transmission segment are evergreen contracts. Standard & Poor's rated ConocoPhillips as "A-" and Superior as "BB-" during 2016.

Terminals Segment

General

Our Terminals segment consists of approximately 2.4 million barrels of storage capacity across three marine terminal sites located in Westwego, Louisiana; Brunswick, Georgia; and Harvey, Louisiana. Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners, and chemical manufacturers, to store a range of products, including petroleum products, distillates, chemicals and agricultural products.

The following table provides information regarding our Terminals segment assets for the years ended December 31, 2016 and 2015.

				Storage Utilization (%)	
	As of December 31, 2016			As of December 31,	
Terminals	Number of Tanks	Approximate Contracted Capacity (Bbls)	Approximate Design Capacity (Bbls)	2016	2015
Westwego	48	957,800	1,044,600	91.7%	93.9%
Brunswick	5	221,000	221,000	100.0%	100.0%
Harvey	34	1,115,000	1,135,200	98.2%	72.9%
Total	87	2,293,800	2,400,800	95.5%	88.4%

Westwego Terminal Operations

The Westwego Terminal site consists of 48 above-ground storage tanks with a combined capacity of 1,044,600 barrels. Our operations support many different commercial customers, including commodity brokers, refiners and chemical manufacturers. Our location within the Port of New Orleans, the warehousing and international distribution attributes this location provides, along with our broad customer base, contributes to the potential diversity of the products customers may want stored in our terminal. The products will generally fall into two broad categories: chemical and agricultural.

Our income from the Westwego Terminal is derived from storage capacity contracts, throughput charges for receipt and delivery of our customers' products; and other services requested by our customers, such as blending services. The terms of our storage capacity contracts range from month-to-month to multiple years, with renewal options.

At the Westwego Terminal, we generally receive our customers' liquid product by river vessel at our Mississippi River dock and by railcar. The product is transferred from the river vessels and railcars to the specified storage tank via the terminal's internal pipeline system. The customer's product is removed from storage at our terminal by truck, railcar and/or water vessel. The length of time that the customer's product is held in storage without transfer varies depending upon the customer's needs.

Brunswick Terminal Operations

The Brunswick Terminal site consists of one 60,000-barrel above-ground storage tank, two 80,000-barrel above-ground storage tanks and two 500-barrel above-ground storage tanks with a combined capacity of 221,000 barrels. The Brunswick Terminal is currently leasing land from the Georgia Ports Authority pursuant to a lease that is in effect until April 2026.

This terminal is ideally suited to serve petroleum, chemical and agricultural customers who need deep-water access and distribution in the southeastern United States. Income from the Brunswick Terminal is derived from storage capacity contracts, throughput charges for receipt and delivery of our customers' products and other services requested by our customers, such as blending services. The terms of our storage capacity contracts will range from month-to-month to multiple years, with renewal options.

At the Brunswick Terminal, we offer product transfer via river vessel, railcar and bulk-liquid carrying truck. At the Brunswick Terminal, the customer's liquid product is received by barge or ship at the dock. The product is transferred from barges or ships to the storage tank via the terminal's internal pipeline system. The customer's product is removed from storage at our terminal by truck, railcar and/or barge or ship. The length of time that the customer's product is to be held in storage without transfer will vary depending on the customer's needs.

Harvey Terminal Operations

The Harvey Terminal is located on 56 acres on the west bank of the Mississippi River in the Port of New Orleans and equipped to handle a wide variety of petroleum and chemical products. Terminal storage operations at the Harvey Terminal commenced in July 2014 and currently consists of 34 above-ground storage tanks with a combined capacity of approximately 1,135,200 barrels. The Harvey Terminal is a full-service storage site, including 3,000 feet of rail track that can accommodate up to 50 cars and a two bay semi-automated truck loading facility. The ship dock does not allow for transfer of railcar or a tank truck. When fully developed, the Harvey Terminal has the potential to provide more than 2 million barrels of storage capacity.

Customers

In our Terminals segment, we generally receive fee-based compensation on guaranteed firm storage contracts and throughput fees charged to our customers when their products are either received or disbursed along with other operational charges associated with ancillary services provided to our customers, such as excess throughput and truck weighing. The terms of our firm storage contracts are multiple years, with renewal options.

PBF Holding Company LLC and Occidental Chemical Corporation are the two largest customers in our Terminals segment and accounted for approximately 17% and 23% respectively, of our segment revenue for the year ended December 31, 2016. Occidental Chemical Corporation and Monsanto Company accounted for approximately 21% and 13%, respectively, of our segment revenue for the year ended December 31, 2015. As of December 31, 2016, the weighted-average remaining life of our guaranteed firm storage contracts in the Terminals segment is approximately 1.04 years. Standard & Poor's rated PBF Holding Company as "BB" and Moody's rated Occidental Petroleum (Occidental Chemical Corporation's parent company) as "A3" during 2016.

Investment in Unconsolidated Affiliates

Delta House

We own a 20.1% direct and indirect non-operating interests in Class A Units of Delta House. Delta House is a semi-submersible floating production system ("FPS") with associated crude oil and natural gas export pipelines located in the Mississippi Canyon region of the deepwater Gulf of Mexico. The FPS receives raw production from deepwater wells, which includes a mixture of crude oil, natural gas, and produced water, and separates the production into its components. The separated crude oil and natural gas pressures are increased, creating pipeline quality crude oil and natural gas that flows into the respective crude oil and natural gas export pipelines. Delta House is operated by LLOG Exploration Offshore, LLC ("LLOG Exploration") and has nameplate processing capacity of 80,000 Bbl/d and 200 MMcf/d and peak processing capacity of 100,000 Bbl/d and 240 MMcf/d.

Main Pass Oil Gathering System

We own a 66.7% non-operated interested in MPOG, a crude oil gathering system located offshore the Southeast coast of Louisiana in the Gulf of Mexico. The approximately 100 mile system has a total design capacity of approximately 160,000 Bbl/d and is currently operated by Panther Operating Companies, LLC, a subsidiary of the minority interest owner, Panther Asset Management, LLC.

Okeanos

We own a 66.7% operated interest in Okeanos, a 100-mile natural gas gathering system located in the Gulf of Mexico with a total capacity of 1.0 Bcf/d. The Okeanos pipeline connects two platforms and one lateral, terminating at the Destin Main Pass 260 platform in the Mississippi Canyon region of the Gulf of Mexico. Contracted volumes on the Okeanos pipeline are based on life-of-field dedication.

Destin

We own a 49.7% operated interest in Destin, a FERC-regulated, 255-mile natural gas transportation system with total capacity of 1.2 Bcf/d. The system originates offshore in the Gulf of Mexico and includes connections with four producing platforms, and six producer-operated laterals, including Delta House. The 120-mile offshore portion of the Destin system terminates at the Pascagoula processing plant, owned by Enterprise Products Partners, LP, and is the single source of raw natural gas to the plant. The onshore portion of Destin is the sole delivery point for merchant-quality gas from the Pascagoula processing plant and extends 135 miles north in Mississippi. Destin currently serves as the primary transfer of gas flows from the Barnett and Haynesville shale plays to Florida markets through interconnections with major interstate pipelines. Contracted volumes on the Destin pipeline are based on life-of-field dedication, dedicated volumes over a given period, or interruptible volumes as capacity permits.

Wilprise

We own a 25.3% non-operated interest in Wilprise, a FERC-regulated, approximately 30-mile NGL pipeline that originates at the Kenner Junction and terminates in Sorrento, Louisiana, where volumes flow via pipeline to a Baton Rouge fractionator.

Tri-States

We own a 16.7% non-operated interest in Tri-States, a FERC-regulated, 161-mile NGL pipeline and sole form of transport to Louisiana-based fractionators for NGLs produced at the Pascagoula plant served by Destin and other facilities.

Competition

The natural gas gathering, compression, treating and transportation business is very competitive. Our competitors in our Gathering and Processing segment include other midstream companies, producers, intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. Our major competitors in this segment include DCP Midstream LLC; Enbridge Energy Partners; LP; Energy Transfer Partners, L.P.; EnLink NGL Marketing, L.P.; Kinder Morgan Energy Partners, and Midcoast Energy Partners.

Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for natural gas, crude oil and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

In our Transmission segment, we compete with other pipelines that serve regional markets, specifically in our Baton Rouge market. An increase in competition could result from new pipeline installations or expansions of existing pipelines. Competitive factors include the commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and natural gas quality issues. Our major competitors for this segment are Columbia Gulf Transmission

Company; EnLink NGL Marketing, L.P.; Enterprise Gas Processing, LLC; Gulf South Pipeline Company, LP; Southern Natural Gas Company; Tennessee Gas Pipeline Company, LLC, and Texas Eastern Pipeline.

In our Terminals segment, we compete with a number of existing storage facilities within the New Orleans to Baton Rouge, Louisiana refining and manufacturing corridor, the southeast USA and the Florida and Georgia area. Our major competitors for this segment are International-Matex Tank Terminals; Kinder Morgan Energy Partners; LBC Tank Terminals; Royal Vopak; Stolt-Nielsen Limited, and Westway Terminals Company LLC.

Other Segment Information

For additional information on our segments, including revenues from customers, profit or loss and total assets, please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 15. "Exhibits and Financial Statement Schedules."

Safety and Maintenance

We are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA"), and by the Pipeline Safety Improvement Act of 2002 ("PSIA"), which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. crude oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in "high-consequence areas," such as high population areas. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The PHMSA issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. We believe that this rule does not apply to any of our pipelines. PHMSA issued, but has yet to publish, its final rule for hazardous liquids pipelines on January 13, 2017. That rule extends regulatory reporting requirements to all liquid gathering lines, requires additional event-driven and periodic inspections, requires use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate inline inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration directed that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. In March 2016, PHMSA published a notice of proposed rulemaking regarding natural gas pipelines that would amend existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. While we cannot predict the outcome of these legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements.

We regularly inspect our pipelines, and third parties assist us in interpreting the results of the inspections.

States are largely preempted by federal law from regulating pipeline safety for interstate lines, but most states are certified by the U.S. Department of Transportation ("DOT") to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. These state crude oil and gas standards may include requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency ("EPA"), community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act (Superfund") and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities, and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety, Superfund and PSM.

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

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

Regulation of Operations

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

Regulation of our terminals require us to maintain and currently hold approvals and permits from federal, state and local regulatory agencies for air quality and water discharge, as well as standard local occupational licenses.

Interstate Natural Gas Pipeline Regulation

Our interstate natural gas transportation systems are subject to the jurisdiction of FERC pursuant to the NGA. Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation of our interstate pipelines extends to such matters as:

- rates, services, and terms and conditions of service;
- the types of services offered to customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

In 2008, FERC issued Order No. 717, a final rule that implements standards of conduct that include three primary rules: (1) the "independent functioning rule," which requires transmission function and marketing function employees to operate independently of each other; (2) the "no-conduit rule," which prohibits passing transmission function information to marketing function employees; and (3) the "transparency rule," which imposes posting requirements to help detect any instances of undue preference. The FERC has since issued four rehearing orders that generally reaffirmed the determinations in Order No. 717 and also clarified certain provisions of the Standards of Conduct.

In April 2008, the FERC issued a Policy Statement regarding the composition of proxy groups for determining the appropriate return on equity for natural gas and crude oil pipelines using FERC's Discounted Cash Flow ("DCF") model for setting cost-of-service or recourse rates. In the policy statement, FERC concluded, among other matters that Master Limited Partnerships ("MLPs") should be included in the proxy group used to determine return on equity for both natural gas and crude oil pipelines, but the long-term growth component of the DCF model should be limited to fifty percent of long-term gross domestic product. The adjustment to the long-term growth component, and all other things being equal, results in lower returns on equity than would be calculated without the adjustment. However, the actual return on equity for our interstate pipelines will depend on the specific companies included in the proxy group and the specific conditions at the time of the future rate case proceeding.

In July 2016, the D.C. Circuit issued its opinion in United Airlines, Inc., et al.v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline partnership owners double-recovering their income taxes. The court vacated FERC’s order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. On December 15, 2016, FERC issued a Notice of Inquiry seeking comment on how to address any double recovery resulting from income tax allowance policy. The ultimate outcome of this proceeding is not certain and could result in changes going forward to FERC’s treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our interstate natural gas pipelines could be affected to the extent they propose new rates or changes to their existing rates or if their rates are subject to complaint or challenged by FERC.

Section 311 Pipelines

Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. To the extent that our intrastate natural gas transportation systems transport natural gas in interstate commerce without an exemption under the NGA, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA, and Part 284 of the FERC's regulations. Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis. The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. The rates, terms and conditions of some transportation services provided on our Section 311 pipeline systems are subject to FERC regulation pursuant to Section 311 of the NGPA. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to FERC's review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by the FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies.

Hinshaw Pipelines

Intrastate natural gas pipelines are defined as pipelines that operate entirely within a single state, and generally are not subject to FERC's jurisdiction under the NGA. Hinshaw pipelines, by definition, also operate within a single state, but can receive gas from outside their state without becoming subject to FERC's NGA jurisdiction. Specifically, Section 1(c) of the NGA exempts from the FERC's NGA jurisdiction those pipelines that transport gas in interstate commerce if (1) they receive natural gas at or within the boundary of a state, (2) all the gas is consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, the FERC issued Order No. 63 authorizing Hinshaw pipelines to apply for authorization to transport natural gas in interstate commerce in the same manner as intrastate pipelines operating pursuant to Section 311 of the NGPA. Hinshaw pipelines frequently operate pursuant to blanket certificates to provide transportation and sales service under the FERC's regulations.

Historically, FERC did not require intrastate and Hinshaw pipelines to meet the same rigorous transactional reporting guidelines as interstate pipelines. However, as discussed below, in 2010 the FERC issued Order No. 735, which increases FERC regulation of certain intrastate and Hinshaw pipelines. See "Market Behavior Rules; Posting and Reporting Requirements."

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. However, some of our natural gas gathering activity is subject to Internet posting requirements imposed by FERC as a result of FERC's market transparency initiatives. 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, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are 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, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC's efforts to promote open access, transparency, and the unbundling of interstate pipeline services has prompted a number of interstate pipelines to transfer their non-jurisdictional 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 natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional 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.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas 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. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have 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 gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our system due to these regulations.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, ("EP Act 2005"). Among other matters, the EP Act 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of the EP Act 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. The EP Act 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation for violations occurring after August 8, 2005. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

The EP Act of 2005 also added a section 23 to the NGA authorizing the FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. In June 2010, the FERC issued the last of its three orders on rehearing further clarifying its requirements.

In May 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission's periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 became effective on April 1, 2011. In December 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract.

In July 2010, for the first time the FERC issued an order finding that the prohibition against buy/sell arrangements applies to interstate open access services provided by Section 311 and Hinshaw pipelines. The FERC denied the numerous requests for rehearing of the July order. However, in October 2010, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should permitted and whether the FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, the FERC granted a blanket waiver regarding such transactions while the FERC is considering these policy issues. The comment period has ended but the FERC has not issued an order.

Offshore Natural Gas Pipelines

Our offshore natural gas gathering pipelines are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires that all pipelines operating on or across the outer continental shelf provide open and nondiscriminatory access to shippers. From 1982 until 2012, the Minerals Management Service ("MMS"), of the U.S. Department of the Interior ("DOI"), was the federal agency that managed the nation's crude oil, natural gas, and other mineral resources on the outer continental shelf, which is all submerged lands lying seaward of state coastal waters which are under U.S. jurisdiction, and collected, accounted for, and disbursed revenues from federal offshore mineral leases. On June 18, 2010, the Minerals Management Service was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"). In October 2011, the BOEMRE was reorganized into and replaced by two separate agencies, the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE"). The BOEM manages the exploration and development of the nation's offshore resources. BOEM seeks to appropriately balance economic development, energy independence, and environmental protection through crude oil and gas leases, renewable energy development and environmental reviews and studies. BSEE works to promote safety, protect the environment, and conserve resources offshore through vigorous regulatory oversight and enforcement.

Sales of Natural Gas and NGLs

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC"), and the Federal Trade Commission ("FTC"). Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Sales of NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

As discussed above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas pipelines and those initiatives may also affect the intrastate transportation of natural gas both directly and indirectly.

Environmental Matters

General

Our operation of pipelines, plants, terminals and other facilities for the gathering, compressing, treating and transporting of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

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

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. 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, hydrocarbons or other waste products into the environment.

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. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

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

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), 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. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate little hazardous waste; however, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly disposal requirements. In December 2016, the EPA and environmental groups entered into a consent decree to address EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking by March 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated soil and 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 Quality and Climate Change

Our operations are subject to the federal Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations and processing plants, 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. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, and the requirements are not expected to be more burdensome to us than to any similarly situated company. As the EPA issues new, lower National Ambient Air Quality Standards ("NAAQS"), we may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For example, in June 2010, the EPA issued a new NAAQS for sulfur dioxide, or SO2, and replaced the 24-hour and annual standards with a more stringent hourly standard. In October 2015, the agency finalized a reduction of the national ambient air quality standard for ozone standard from 75 parts per billion to 70 parts per billion; both nitrogen oxides and VOCs are ozone precursors. This reduction is expected to increase the number of ozone nonattainment areas. In October 2016, the EPA also finalized Control Technology Guidelines for emissions of VOCs from crude oil and natural gas industry sources to be relied upon by states when implementing the ozone standard in ozone nonattainment areas. We believe that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for crude oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. The established specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. Initial compliance and ongoing compliance with the new subset of rules required capital expenditures and ongoing compliance expenses. Following the publication of the final rule, the EPA received petitions for reconsideration of certain aspects of the standards. On April 12, 2013, the EPA published proposed updates to the NSPS Section OOOO storage tank requirements. On September 23, 2013, the EPA published final revisions to the NSPS Section OOOO storage tank requirements, including a phase-in of installation of VOC controls and alternate limits for tanks where emissions have declined. The EPA issued revised definitions related to the stages of well completions and amended storage tank requirements under NSPS Section OOOO in December 2014 and further revised the storage tank requirements in March 2015. More recently, in June 2016, the EPA published updates to new source performance standard requirements that would impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. Similarly in November 2016, the BLM issued rules requiring additional efforts by producers to reduce venting, flaring, and leaking of natural gas produced on federal and Native American lands.

A number of states have adopted or considered programs to reduce “greenhouse gases,” or GHGs and the EPA has declared that GHGs “endanger” public health and welfare, and is regulating GHG emissions from mobile sources such as cars and trucks. According to the EPA, this final action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, particularly the Prevention of Significant Deterioration program and Title V permitting. These requirements for stationary sources took effect on January 2, 2011; however, in June 2014 the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA’s greenhouse gas permitting rules to the extent they impose a requirement to obtain a federal air permit based solely on emissions of greenhouse gases. Large sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. The EPA has also published various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems. In October 2015, the EPA amended and expanded greenhouse gas reporting requirements to all segments of the crude oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines, starting with the 2016 reporting year, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rule with the new source performance standards.

The permitting, regulatory compliance and reporting programs taken as a whole increase the costs and complexity of operating oil and gas operations in compliance with these legal requirements, with resulting potential to adversely affect our cost of doing business, demand for the oil and gas we transport and may require us to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Water Discharges

The Federal Water Pollution Control Act ("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 U.S. and to conduct construction activities in waters and wetlands. In May 2015, the EPA and the U.S. Army Corps of Engineers issued a final rule to clarify which waters and wetlands are subject to Clean Water Act regulation. The implementation of this rule was stayed nationwide in October 2015. On February

28, 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to review and, consistent with applicable law, to initiate rulemaking to rescind or revise the rule. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill Prevention Control and Countermeasure ("SPCC") requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon 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. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flow.

Safe Drinking Water Act

The underground injection of crude oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. We own and operate an acid gas disposal well in Wayne County, Mississippi, as part of our Bazor Ridge gas treating facilities. This well takes a combination of hydrogen sulfide and carbon dioxide recovered from the raw field natural gas feeding the Bazor Ridge Gas plant and injects it into an underground formation permitted for this purpose. The well received an Underground Injection Control ("UIC") Class 2 permit through the Mississippi state oil and gas board in 1999. As part of our permit requirements, we perform regular inspection, maintenance and reporting to the state on the condition and operations of this well which is adjacent to our processing plant. We believe that our facilities will not be materially adversely affected by such requirements.

Endangered Species

The Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. 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. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

National Environmental Policy Act

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance, and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo NEPA review. Many of our activities are covered under categorical exclusions that result in a shorter NEPA review process. The Council on Environmental Quality has issued final guidance to reinvigorate NEPA reviews that, while intended to streamline the process, may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Anti-terrorism Measures

The federal Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present “high levels of security risk.” Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory provisions, including requirements regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

Title to Properties and Rights-of-Way

Our real property falls into two categories: i) parcels that we own in fee and ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remaining land on which our plant sites and major facilities are located, are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. Our predecessors leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Employees

We do not have any employees. The officers of our General Partner manage our operations and activities. As of December 31, 2016, our General Partner employed approximately 329 people who provide direct, full-time support to our operations. All of the employees required to conduct and support our operations are employed by our General Partner. None of these employees are covered by collective bargaining agreements, and our General Partner considers its employee relations to be positive.

General

We make certain filings, and amendments thereto, with the Securities and Exchange Commission (the "SEC"), including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports. All of these filings are available as soon as reasonably practicable after the electronic filing with the SEC free of charge on our website, www.americanmidstream.com. The filings are also available at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549 or by calling the SEC at 1-800-SEC-0330. Additionally, the filings are available on the Internet at www.sec.gov. We intend to use our website as a means for disseminating information in accordance with Regulation FD under the Exchange Act. The information contained on our website is not part of, nor is it incorporated by reference into, this Annual Report on Form 10-K.

Item 1A. Risk Factors

Limited partner units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this Annual Report in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition, results of operations or cash flows could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

The risks described below are not the only ones that we face. Additional risks not presently known to us or that we currently deem immaterial individually or in the aggregate may also impair our business operations. This Annual Report also contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of various factors, including the risks and uncertainties faced by us described below.

Risks Related to the Business of the Combined Company

We recently identified a material weakness in our internal controls. If we fail to remediate this material weakness or otherwise fail to develop, implement and maintain appropriate internal controls in future periods, our ability to report our financial condition and results of operations accurately and on a timely basis could be adversely affected.

We have identified a material weakness in our internal controls over the level of accounting knowledge, expertise and training to ensure that complex, non-routine transactions were recorded appropriately. This control deficiency resulted in out-of-period adjustments recorded to our consolidated statement of operations in the fourth quarter of 2016 and a revision to our 2015 consolidated balance sheet and consolidated statement of cash flows. Accordingly, our management determined that, as of December 31, 2016, our disclosure controls and procedures and our internal control over financial reporting were not effective. The specific material weakness and our remediation efforts are described in Item 9A, Controls and Procedures. A “material weakness” is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis. We cannot assure you that we will adequately remediate the material weakness or that additional material weaknesses in our internal controls will not be identified in the future. Any failure to maintain or implement required new or improved controls, or any difficulties we encounter in their implementation, could result in additional material weaknesses, or could result in material misstatements in our financial statements. These misstatements could result in restatements of our financial statements, cause us to fail to meet our reporting obligations or cause investors to lose confidence in our reported financial information.

We are in the process of remediating the identified material weakness in our internal controls, but we are unable at this time to estimate when the remediation effort will be completed. During the course of implementing additional processes and controls, as well as controls operating effectiveness testing, we may identify additional control deficiencies, which could give rise to other material weaknesses, in addition to the material weakness described above. As we continue to evaluate and work to improve our internal control over financial reporting, we may determine to take additional measures to address material weakness or determine to modify certain of the remediation measures. It may be difficult or costly to remediate the material weakness, including through hiring new personnel with sufficient and tailored skill sets. If we fail to remediate this material weakness, there will continue to be an increased risk that our future financial statements could contain errors that will be undetected. Further and continued determinations that there are material weaknesses in the effectiveness of our internal controls could reduce our ability to obtain financing or could increase the cost of any financing we obtain and require additional expenditures of resources to comply with applicable requirements. The existence of a material weakness could result in errors in our financial statements that could result in a restatement of financial statements, which could cause us to fail to meet our reporting obligations, lead to a loss of investor confidence and have a negative impact on the trading price of our common stock.

Our current and future indebtedness levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

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;
- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make principal and interest payments on our indebtedness;
- our indebtedness level may make us more vulnerable than our competitors with less debt 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.

Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to make cash distributions to our unitholders.

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

The indenture governing the notes and our credit facility contain certain financial covenants and ratios and other restrictions. We may have difficulty maintaining compliance with such financial covenants and ratios and other restrictions, which could adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

We are dependent upon certain earnings and cash flow generated by our operations in order to meet our debt service obligations. We also depend on our credit facility for working capital and future expansion capital needs and, as necessary, to fund a portion of cash distributions to unitholders. The indenture governing the notes and our revolving credit facility contain, and any future financing agreements may contain, operating and financial restrictions and covenants that could restrict our ability to finance future operations or capital needs, or to expand or pursue our business activities, which may, in turn, limit our ability to pay distributions to our unitholders. For example, our revolving credit facility limits our ability to, among other things:

- incur or guarantee additional indebtedness or issue preferred units;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- redeem or repay other debt or make other restricted payments;
- make capital expenditures above specified amounts;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- create non-guarantor subsidiaries;
- enter into sale and leaseback transactions;
- merge or consolidate with another company;
- transfer, sell or otherwise dispose of assets, including equity interests in our subsidiaries;
- cancel or modify material contracts;
- sell our income or receivables;

•enter into “take-or-pay” contracts; and
•amend our organizational documents.

Our Second Amended and Restated Credit Agreement contains certain financial covenants, including (i) a consolidated total leverage ratio that requires our indebtedness not to exceed 5.00 times adjusted consolidated EBITDA (as defined in the revolving credit facility) for the prior twelve month period, adjusted in accordance with the Second Amended and Restated Credit Agreement (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant may be increased to 5.50 times adjusted consolidated EBITDA), (ii) a minimum interest coverage ratio that requires our adjusted consolidated EBITDA to exceed consolidated interest charges by at least 2.50 times for the prior twelve month period, and (iii) a consolidated secured leverage ratio that requires our consolidated secured indebtedness not to exceed 3.50 times adjusted consolidated EBITDA for the prior twelve month period. The financial covenants in our Second Amended and Restated Credit Agreement may limit the amount available to us for borrowing to less than $900.0 million. As of December 31, 2016, under our Credit Agreement at that time, our consolidated total leverage ratio was 4.07 and our interest coverage ratio was 7.43, which were in compliance with the financial covenants. Under the Second Amended and Restated Credit Agreement, the maximum permitted consolidated total leverage ratio for the fiscal year is 5.00 and can increase to 5.50 with the election of a Specified Acquisition Period. As of December 31, 2016, we had approximately $711.3 million of outstanding borrowings under our Credit Agreement existing at that time. Our ability to comply with these covenants and ratios in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of the financial markets and commodity price levels. Our failure to comply with any of the covenants or ratios under our revolving credit facility could result in a default, which could cause all of our existing indebtedness to become immediately due and payable. If the payment of our indebtedness is accelerated and we are unable to repay the indebtedness in full, our lenders could foreclose on the assets pledged by us and the guarantors under the revolving credit facility. In that case, our assets may be insufficient to repay such indebtedness in full.

Because of the natural decline in production from existing wells in our areas of operation, our success depends on our ability to obtain new sources of natural gas, NGLs 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 could adversely affect our business and operating results.

The commodity volumes that support our business are dependent on the level of production from natural gas and crude oil wells connected to our systems, including volumes from significant customers, the production of which will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas and crude oil. 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 and (ii) our ability to compete for volumes from successful new wells.

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:

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

Fluctuations in energy prices, like the decline in commodity prices of crude oil, natural gas and NGLs from recent highs reached in mid-2014, can also greatly affect the development of new reserves. Further declines in crude oil, natural gas and NGLs prices could have a negative impact on exploration, development and production activity, and, if sustained, are likely to lead to further decreases in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices continue to remain low or fluctuate, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants in our revolving credit facility. Reduced profitability may also result in future non-cash impairments of long-lived assets, goodwill, or intangible assets.

Because of these and other factors, even if new natural gas, NGL and crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

Natural gas, crude oil, NGL and other commodity prices are volatile, and a reduction in these prices in absolute terms, or an adverse change in the prices of natural gas and NGLs relative to one another, could adversely affect our net income, gross margin and cash flow and our ability to make distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. Natural gas prices have been under downward pressure in recent years and were highly volatile in 2014. The NYMEX daily settlement price for natural gas for the forward month contract in 2016 ranged from a high of $3.80 per MMBtu to a low of $1.49 per MMBtu. NGL prices are generally positively correlated to the price of WTI crude oil, which has also exhibited frequent and substantial fluctuations. Oil prices declined dramatically in late 2014 and remained low in 2015 and early 2016. The NYMEX daily settlement price for WTI crude oil for the forward month contract in 2016 ranged from a high of $54.45 per Bbl to a low of $26.21 per Bbl.

The markets for and prices of natural gas, crude oil, NGLs and other hydrocarbon commodities depend on factors that are beyond our control. These factors include the supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

•worldwide economic conditions;
•worldwide political events, including actions taken by foreign oil and gas producing nations;
•worldwide weather events and conditions, including natural disasters and seasonal changes;
•the levels of world-wide and domestic production and consumer demand;
•the availability of imported, or market for exported, liquefied natural gas, or LNG;
•the market for exported crude oil;
•the availability of transportation systems with adequate capacity;
•the volatility and uncertainty of regional pricing differentials;
•the price and availability of alternative fuels;
•the effect of energy conservation measures;
•the nature and extent of governmental regulation and taxation; and
•the current and anticipated future prices of natural gas, crude oil, NGLs and other commodities.

In our Gathering and Processing segment, we have exposure to direct commodity price risk under percent-of-proceeds processing contracts as well as under our elective processing arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers and retain an agreed percentage of the proceeds (in cash or in-kind) from the sale at market prices of pipeline-quality natural gas and NGLs resulting from our processing activities. We also purchase natural gas at various receipt points, process the gas at a third-party owned natural gas processing facility and sell our portion of the residue gas and NGLs. Under percent-of-proceeds arrangements, our revenue and our cash flows increase or decrease as the prices of natural gas, NGLs and crude oil fluctuate. When we process natural gas that we purchase for our own account, the relationship between natural gas prices and NGL prices also affects our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us to process the natural gas that we purchase and process for our own account. When natural gas prices are high relative to NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and because of the increased cost (principally that of natural gas shrink that occurs during processing and use of natural gas as a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed pursuant to our elective processing arrangements. For the years ended December 31, 2016 and 2015, percent-of-proceeds arrangements accounted for approximately 11.1% and 14.3%, respectively, of our gross margin, or 19.4% and 22.7%, respectively, of the segment gross margin in our Gathering and Processing segment.

If the current commodity price environment continues, it could result in a further decrease in exploration and development activities in the fields served by our gathering and pipeline transmission systems and our natural gas processing plants, which could lead to further reduced utilization of these assets. During periods of natural gas, crude oil, or NGL declines, the level of drilling activity generally decrease. When combined with a reduction of cash flow resulting from lower commodity prices, a reduction in our producers’ borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers’ spending for drilling activity, which could result in lower volumes being transported on our gathering and transmission systems.

In addition, in our refined products terminals and storage segment we generate revenue from (i) blending activities, such as ethanol blending and butane blending, and (ii) our vapor recovery units. Our blending activities are subject to direct commodity price exposure. Any significant reduction in the amount of services we provide to our customers because of direct or indirect commodity price exposure and any significant reduction in the refined products that we sell could have a material adverse effect on our business, results of operations, financial condition and our ability to make distributions to our unitholders.

Further, results of operations related to the retail distribution of propane is primarily based on the cents-per-gallon difference between the sales price we charge our customers and our costs to purchase and deliver propane to our propane distribution locations. We enter into propane sales commitments with a portion of our customers that provide for a contracted price agreement for a specified period of time. The propane cost per gallon is subject to various market conditions and may fluctuate based on changes in demand, supply and other energy commodity prices, such as crude oil and natural gas prices. We employ risk management techniques that attempt to mitigate risks related to the purchasing, storing, transporting and selling of propane. However, sudden and sharp propane cost increases cannot be passed on to customers with contracted pricing arrangements. In addition, even upon the expiration of short-term contracts, we may face competitive or relationship pressure to minimize any price increases. Therefore, these commitments expose us to product price risk and reduced profit margins if those transactions are not immediately hedged with an offsetting propane purchase commitment.

Historically, we have relied on cash flows from our operations, borrowing under our revolving credit facility and the capital markets to fund our operations and capital expenditures and acquisitions. If commodity prices remain volatile, our cash flows could be adversely affected which, combined with limited availability under our revolving credit facility, could adversely affect our ability to finance our operations and capital expenditures and acquisitions.

Our growth strategy, and ability to fund expansion capital projects, requires access to new capital. Tightened capital markets or other factors that increase our cost of capital, or limit our access to capital, could impair our ability to grow.

We continuously consider potential acquisitions and opportunities for expansion capital projects. Acquisition opportunities arise quickly and unexpectedly, may occur at any time and may be significant in size relative to our existing assets and operations. Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth strategy. Our ability to maintain our targeted credit profile, including our target debt-to-equity ratio, could affect our cost of capital as well as our ability to execute our growth strategy. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets.

Due to these factors, we cannot be certain that funding for our capital needs will be available from bank credit arrangements, our revolving credit facility or capital markets on acceptable terms. 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.

Our business is subject to a number of weather related risks, including severe weather in the U.S. Gulf of Mexico, which can cause significant damage and disruption to our business interests located in that region, and abnormal weather conditions, which can reduce the demand for propane.

The U.S. Gulf of Mexico experiences hurricanes and other extreme weather conditions on a frequent basis, the frequency of which may increase with climate change. Our High Point system, our Offshore Texas system, our Destin system, our Okeanos system, our non-operated interests in MPOG and Delta House and any future systems that we acquire in the U.S. Gulf of Mexico, are susceptible to adverse weather conditions in the U.S. Gulf of Mexico, including hurricanes and other extreme weather conditions. Our insurance may not cover all associated loss. High winds, storm surge, and turbulent seas can cause significant damage and curtail these operations for extended periods during and after such weather conditions, which may result in decreased revenues from our interests in these operations. In addition, these adverse weather conditions in the U.S. Gulf of Mexico can affect producers connected to our facilities even if our facilities are not damaged, which may result in decreased revenues from our interests in these operations.

In addition, weather conditions have a significant impact on the demand for propane. Actual weather conditions can vary substantially from year to year, significantly affecting our financial performance. Many of our customers rely on propane primarily as a heating source during the winter. Warmer than normal winter temperatures can substantially reduce our retail commercial and wholesale propane volumes. Conversely, our cylinder exchange business experiences higher volumes in the spring and summer. Sustained periods of poor weather, particularly in the grilling season, can reduce consumers' propensity to purchase and use grills and other propane-fueled appliances, thereby reducing demand for cylinder exchange and our outdoor products.

To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Generally, we either consider our customers creditworthy or require those who are not creditworthy to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies will not completely eliminate customer and counterparty credit risk. Our customers and counterparties include entities whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities.

In addition, in connection with the acquisition of certain of our assets, we have entered into agreements pursuant to which various counterparties have agreed to indemnify us, subject to certain limitations, for certain matters arising from the pre-closing ownership and operation of assets.

The current low commodity price environment has negatively impacted many oil and gas companies causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts. To the extent one or more of our key customers or counterparties commences bankruptcy proceedings, our contracts with such customers or counterparties may be subject to rejection under applicable provisions of the United States Bankruptcy Code or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, results of operations, cash flows and financial conditions. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write down or write off accounts receivable. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution could be adversely affected.

Our natural gas gathering and processing and transportation systems connect to other pipelines or facilities, the majority of which are owned and operated by third parties. For example, our elective processing arrangements are entirely dependent on the Toca plant for processing services and the Sonat pipeline for natural gas takeaway capacity. As another example, our North Little Rock terminal is currently supplied by the TEPPCO Pipeline and is expected, in the future, to also be supplied by Magellan’s Fort Smith Pipeline, while our Caddo Mills terminal is supplied by the Explorer Pipeline. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities and others upon which we rely may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. For example, the explosion and fire at the Pascagoula Gas plant in June of 2016 suspended operations from that facility for over eight months. If any of these pipelines or other midstream facilities becomes unable to receive or transport natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenue and cash available for distribution may be adversely affected.

Our hedging activities may not be effective in reducing our direct exposure to commodity price risk and may, in certain circumstances, increase the variability of our cash flows.

From time to time, we have entered into derivative transactions related to only a portion of the equity volumes of commodities to which we take title. As a result, we will continue to have direct commodity price risk to the unhedged portion of our commodity equity volumes. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity. The derivative instruments we utilize for these hedges are based on posted market prices, which may be lower than the actual commodity prices that we realize in our operations. In addition, when there is not a hedging instrument available for a commodity to which we take title, we are forced to use an alternative hedge that may not adequately reduce price risk. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and, in certain circumstances, may actually increase the variability of our cash flows. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. Further, there may be times where we terminate or enter into offsetting positions depending on our view of future market prices.

The adoption and implementation of new statutory and regulatory requirements for swap transactions could have an adverse impact on our ability to hedge risks associated with our business.

We hedge a portion of our commodity risk and our interest rate risk. The federal government regulates the derivatives market and entities, including businesses like ours, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation. Under the CFTC's regulations, we are subject to reporting and recordkeeping obligations for transactions involving non-financial swap transactions. The CFTC initially adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in Federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. On November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The CFTC has imposed mandatory clearing requirements on certain categories of swaps, including certain interest rate swaps, but has exempted derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as us has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. We believe our hedging transactions will qualify for the "commercial end user" exception. The Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Our failure or our counterparties' failure to perform on obligations under commodity derivative and financial derivative contracts could have a material adverse effect on our financial condition, results of operations and cash flows.

We enter into hedging arrangements to manage the cost of propane in our cylinder exchange business. We also may from time to time enter into derivative instruments to hedge our exposure to variable interest rates. Volatility in the oil and gas commodities sector for an extended period of time or intense volatility in the near-term could impair our or our counterparties' ability to meet margin calls, which could cause us or our counterparties to default on commodity and financial derivative contracts. This could have a material adverse effect on our liquidity or our ability to procure product supply at prices reasonable to us or at all.

We do not control certain of the entities that own our projects and we may acquire future projects that we do not control.

We own a 49.7% membership interest in Destin, 20.1% of the Class A Units of Delta House FPS LLC and Delta House Oil and Gas Lateral LLC, a 16.7% membership interest in Tri-States, a 66.7% membership interest in Okeanos, and a 25.3% membership interest in Wilprise. We do not control these projects or project entities' governing boards. As a result, our ability to pay cash distributions to our unitholders will depend in part on the performance of these projects or entities and their distributions of cash to us.

Further, additional projects we may acquire may be subject to a similar structure where we do not own a majority of the project or project entity and we may invest in joint ventures in which we share control or in which we are a minority investor. In these instances, the majority investor or controlling investor may not have the level of experience, technical expertise, human resources management and other attributes necessary to operate these assets optimally.

A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining or heating industries, could adversely affect the profitability of our midstream business.

Various factors impact the demand for natural gas, NGLs and condensate, including general economic conditions, extended periods of ethane rejection, 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. In addition, certain of our operating costs and expenses are fixed and do not vary with the volumes we transport or redeliver. These costs and expenses may not decrease ratably or at all should we experience a reduction in the volumes we sell, transport or redeliver. As a result, a decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining or heating industries, could decrease volumes and adversely affect the margin and profitability of our midstream business.

We depend on a relatively small number of customers for a significant portion of our gross margin. The loss of any one of these customers could adversely affect our ability to make distributions.

A significant percentage of the gross margin in each of our segments is attributable to a relatively small number of customers. Additionally, a number of customers upon which our business depends are small companies that may have limited access to capital or that may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better capitalized companies. For information regarding our concentration of customers and associated credit risk by segment, please refer to “Part I, Item 1. Business” in this Annual Report. Although we have gathering, processing and transmission contracts with significant customers of varying duration and commercial terms, if one or more of these customers were to default on their contract or if we were unable to renew our contract with one or more of these customers on favorable terms, we may not be able to replace these 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 may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross margin.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.

We compete with other midstream companies in our areas of operation. In addition, 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, transportation or terminaling systems 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 in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our gathering, processing, transportation and terminal contracts subject us to renewal risks.

We gather, purchase, process, transport and sell most of the commodities on our systems under contracts with terms of various durations, including contracts that have terms as short as one month or which are cancellable on as little as 30 days’ notice, and which may be difficult to extend or replace. We provide NGL sales and distribution services, refined products terminals, crude oil pipeline services and above-ground storage services that support various commercial customers. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with percent-of-proceeds contracts may choose to switch to fee-based gathering and transportation contracts, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenue, gross margin and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected.

We may not successfully balance our purchases and sales of natural gas, which would increase our exposure to commodity price risks.

We purchase from producers and other suppliers a substantial amount of the natural gas that flows through our pipelines and processing facilities for sale to third parties, including natural gas marketers and other purchasers. We are exposed to fluctuations in the price of natural gas through volumes sold pursuant to percent-of-proceeds arrangements as well as through volumes sold pursuant to our fixed-margin contracts.

In order to mitigate our direct commodity price exposure, we do not enter into natural gas hedge contracts, but rather attempt to balance our natural gas sales with our natural gas purchases on an aggregate basis across all of our systems. We may not be successful in balancing our purchases and sales, and as such may become exposed to fluctuations in the price of natural gas. For example, we are currently net purchasers of natural gas on certain of our systems and net sellers of natural gas on certain of our other systems. Our overall net position with respect to natural gas can change over time and our exposure to fluctuations in natural gas prices could materially increase, which in turn could result in increased volatility in our revenue, gross margin and cash flows.

Although we enter into back-to-back purchases and sales of natural gas in our fixed-margin contracts in which we purchase natural gas from producers or suppliers at receipt points on our systems and simultaneously sell an identical volume of natural gas at delivery points on our systems, we may still be exposed to commodity price risks. For example, the volumes or timing of our purchases and sales may not correspond. In addition, a producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to become unbalanced. If our purchases and sales are unbalanced, we will face increased exposure to commodity price risks, which in turn could result in increased volatility in our revenue, gross margin and cash flows.

The risk management policy governing our crude oil supply activities cannot eliminate all risks associated with our crude oil pipelines and storage business, and we cannot ensure that employees of our general partner will fully comply with the policy at all times, both of which could impact our financial and operational results and, in turn, our ability to make cash distributions to our unitholders.

We have in place a risk management policy that seeks to establish limits for the exposure in our crude oil pipelines and storage business by requiring that we restrict net open positions through the concurrent purchase and sale of like quantities of crude oil to create transactions intended to lock in positive margins based on the timing, location or quality of the crude oil purchased and delivered. Our risk management policy, however, cannot eliminate all risks. Any event that disrupts our anticipated physical supply of crude oil could create a net open position that would expose us to risk of loss resulting from price changes.

Moreover, we are exposed to price movements on products that are not hedged, such as our crude oil line fill, which must be maintained to operate our crude oil pipeline system. We are also exposed to certain price risks related to basis differentials. Basis differentials can be created to the extent that we hold or sell crude oil of a grade or quality at a location or at a time that differs from the specific delivery terms with respect to grade, quality, time or location of the applicable offsetting agreement. If this occurs, we may not be able to use the physical markets to fully hedge our price risk. Our exposure to price risks could impact our operational and financial results and our ability to make cash distributions to our unitholders.

We are also subject to the risk that employees of our general partner involved in our crude oil operations may not comply at all times with our risk management policy. We cannot ensure that all violations of our risk management policy, particularly if deception or other intentional misconduct is involved, will be detected prior to our businesses being materially affected.

A prolonged decline in index prices at Cushing, relative to other index prices, could reduce the demand for the services we provide in our crude oil storage business.

In recent years, a shortfall in takeaway pipeline capacity has at times led to an oversupply of crude oil at Cushing. This was cited as a principal reason for the decline in the West Texas Intermediate Index (“WTI Index”) price used at Cushing relative to other crude oil price indexes, including the Brent Crude Index over the same period. While the WTI Index price has recovered compared to the Brent Crude Index, a renewed decline in the WTI Index price relative to other index prices may reduce demand for transportation of crude oil to, and storage at our facility in, Cushing, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

The results of our crude oil storage business could be adversely affected during periods in which the overall forward market for crude oil is backwardated.

The results of our crude oil storage business are influenced by the overall forward market for crude oil. A contango market (meaning that the price of crude oil for future delivery is higher than the current price) has a favorable impact on the demand for crude oil storage as it allows a party to simultaneously purchase crude oil at current prices for storage and sell at higher prices for future delivery. Conversely, a backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) can negatively affect the demand for crude oil storage because there is little incentive to store crude oil when prices offered for future delivery are expected to be lower. Accordingly, a backwardated market can negatively impact the demand for crude oil storage. If the forward market for crude oil is backwardated at times when we are renewing our crude oil storage contract or entering into new crude oil storage contracts, it could adversely affect the results in our crude oil storage business.

High prices for propane can lead to customer conservation and attrition, resulting in reduced demand for our products.

Propane prices are subject to fluctuations in response to changes in wholesale prices and other market conditions beyond our control. Therefore, our average retail sales prices can vary significantly within a heating season or from year to year as wholesale prices fluctuate with propane commodity market conditions. During periods of high propane costs our selling prices generally increase. High prices can lead to customer conservation and attrition, resulting in reduced demand for our products.

We are dependent on third-party propane providers, which subjects us to increased costs and interruptions in supply and transportation.

While we intend to supply a portion of our propane needs, we still rely on third-party propane providers to supply a majority of our propane needs. A shortage in our propane supply or the propane supply from our principal third-party providers may require us to procure additional propane from alternative providers. The cost of procuring supplies and transporting those supplies from such alternative providers might be materially higher than expected and our earnings could be affected. Accordingly, disruptions in supply in certain areas could also have an adverse impact on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Energy efficiency, advances in technology and competition from other energy sources may affect demand for propane and increases in propane prices may cause our residential customers to increase their conservation efforts.

The national trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, has generally reduced the demand for propane. Propane also competes with other sources of energy such as electricity, natural gas and fuel oil, some of which can be less costly for equivalent energy value. In particular, the gradual expansion of the nation’s natural gas distribution systems has increased the availability of affordable natural gas in rural areas, which historically found propane to be the more cost- effective choice. We cannot predict the effect that future conservation measures, technological advances in heating, conservation, energy generation or other devices or the development of alternative energy sources might have on our operations. As the price of propane increases, some of our customers tend to increase their conservation efforts and thereby decrease their consumption of propane.
A significant increase in motor fuel costs or other commodity prices may adversely affect our profits.

Motor fuel is a significant operating expense for us in connection with the operation of both our crude oil pipelines and storage and NGL distribution and sales segments. Although contracts typically have a fuel surcharge, a significant increase in motor fuel prices will result in increased transportation costs to us. The price and supply of motor fuel is unpredictable and fluctuates based on events we cannot control, such as geopolitical developments, supply and demand for oil and gas, actions by oil and gas producers, war and unrest in oil-producing countries and regions, regional production patterns and weather concerns. Additionally, we may be affected by increases in the cost of materials used to produce portable propane cylinders. As a result, any increases in these prices may adversely affect our profitability and competitiveness.

Environmental, health and safety costs and liabilities, and changing environmental, health and safety regulation, could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to various environmental, health and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental, health and safety laws or regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable laws, regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Failure to comply with these requirements may expose us to fines, penalties, remedial liabilities and/or interruptions or delays in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, future environmental, health and safety law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations. Areas of potential future environmental, health and safety law development include the following items:

Greenhouse Gases/Climate Change. From time to time, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases but no such legislation has yet been adopted by Congress. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy sources, or use of replacement fuels with lower carbon content.

The EPA initiated the regulation of greenhouse gases under its Clean Air Act authority in 2009, requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA annually. In October 2015, the EPA amended and expanded greenhouse gas reporting requirements to all segments of the crude oil and natural gas industry, including gathering and compression facilities and blowdowns of natural gas transmission pipelines, starting with the 2016 reporting year, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rule with the new source performance standards. A number of our facilities, including our Bazor Ridge and Chatom systems, are subject to greenhouse gas reporting, and we have filed annual emission reports for these facilities since March 2012.

Federal agencies also have begun directly regulating emissions of methane (a greenhouse gas) from crude oil and natural gas operations. In June 2016, the EPA issued new source performance standards for methane from new and modified crude oil and natural gas industry sources. These regulations will expand upon the 2012 EPA new source performance standard rulemaking for equipment-specific emissions control requirements, and will, for example, require additional controls for pneumatic controllers and pumps, and compressors, and impose leak detection and repair requirements for natural gas compressor and booster stations. The EPA had announced plans to begin work on regulations to regulate methane emissions from existing oil and gas sources. In November 2016, the BLM issued rules requiring additional efforts by producers to reduce venting, flaring, and leaking of natural gas produced on federal and Native American lands. On an international level, in April 2016, the United States became one of almost 175 nations that signed onto the Paris Agreement, an international climate change agreement that calls for countries to set their own greenhouse gas emissions targets and be transparent about the measures each country will use to achieve its greenhouse gas emissions targets.

The adoption and implementation of any international, federal, state or local regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the commodities that we buy and/or sell, transport, store or otherwise handle in connection with our midstream services. In addition, the adoption and implementation of any international, federal, state or local regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, the equipment and operations of our producer customers could affect their ability to produce the commodities that we buy and/or sell, transport, store or otherwise handle in connection with our midstream services. The potential increase in our operating costs could include among other things costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage. These developments could have a material adverse effect on our financial position, results of operations and cash flows.

Hydraulic Fracturing. Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas and crude oil production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. From time to time, the United States has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing, and several governmental reviews, including a study being performed by the EPA, are underway that focus on environmental aspects of hydraulic fracturing activities. Moreover, some states and localities, have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production, or otherwise limit the use of the technique. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Increased regulation to the hydraulic fracturing process also could lead to a reduction in crude oil and natural gas drilling activities using hydraulic fracturing techniques, whereas increased public opposition to activities using such techniques may result in operational delays, restriction or litigation. Additional legislation or regulation could also lead to operational delays and/or increased operating costs in the production of crude oil and natural gas incurred by our customers or could make it more difficult for them to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling or production of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream business and have a material adverse effect on our financial position, results of operations and cash flows.

The value of our interests in operations located in the U.S. Gulf of Mexico could be adversely impacted by increased regulation and continuing regulatory uncertainty.

Operations in the U.S. Gulf of Mexico have been subject to an increasingly stringent regulatory environment including government regulations focused on offshore operating requirements, spill cleanup, and enforcement matters. These regulations also implement additional safety and certification requirements applicable to offshore activities in the U.S. Gulf of Mexico. Certain operating assets such as our High Point system, Destin system, Okeanos system and our Offshore Texas system, and certain non-operated interests in operations located in the U.S. Gulf of Mexico that we currently hold or may hold in the future, are subject to such increased regulations, including our non-operated interests in MPOG and Delta House. In addition, the Bureau of Safety and Environmental Enforcement and the Bureau of Ocean Energy Management has increased regulatory activity including shortening the time period a line may be inactive before it must be removed or abandoned and requiring additional supplemental bonding or other forms of providing abandonment security for offshore facilities on the Outer Continental Shelf. These new regulations have increased our operating costs, and the operating costs of our producer customers. As a result, the value of our interests in these operations may be adversely affected by these regulations. Future regulatory requirements could delay activities from these operations and reduce our revenues, resulting in reduced cash flows and profitability. Moreover, any failure to satisfy these regulatory requirements by our producing customers could result in the commencement of enforcement proceedings or the taking of other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, could materially reduce the demand for our services.

Significant portions of our pipeline systems have been in service for several decades and we have a limited ownership history with respect to all of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Significant portions of the pipeline systems that we have purchased had been in service for many decades prior to our purchase. Consequently, our executive management team has a limited history of operating such assets. There may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

We may incur significant costs and liabilities as a result of increasingly stringent pipeline safety regulation, including pipeline integrity management program testing and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the DOT, through PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located in “high consequence areas,” including high population areas, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators, including us, to:

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

In addition, many states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with our non-exempt pipelines, particularly our AlaTenn and Midla pipelines. We currently estimate that we will incur future costs of approximately $2.0 million during 2017 to complete the testing required by existing DOT regulations. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, should we fail to comply with DOT regulations, we could be subject to penalties and fines.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), which became law in January 2012, increases the penalties for safety violations, establishes additional safety requirements for newly constructed pipelines and requires studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. More recently, in June 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act") that extends PHMSA's statutory mandate through 2019 and, among other things, requires PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing.

In April 2015, PHMSA proposed rulemaking that would require leak detection for all "hazardous liquid pipelines" such as crude oil and NGL pipelines and require periodic assessment of hazardous liquid pipelines not already covered by the integrity management requirements. On January 13, 2017, PHMSA issued a final rule requiring the use of leak detection systems beyond HCAs to all regulated, non-gathering hazardous liquid pipelines and requiring integrity assessments at least once every ten years of onshore, piggable, transmission hazardous liquid pipeline segments located outside of HCAs. The effective date of this final rule is currently uncertain due to a regulatory freeze implemented by the Trump administration. In addition, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation services. Additionally, legislative and regulatory changes may also result in higher penalties for the violation of federal pipeline safety regulations and the 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 costs of compliance associated with such requirements.

We and JPE will incur substantial transaction-related costs in connection with the JPE Merger.

We and JPE expect to incur a number of non-recurring transaction-related costs associated with combining the operations of the two organizations and achieving desired synergies. These fees and costs will be substantial. Unanticipated costs may be incurred in the integration of the businesses of AMID and JPE. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction- related costs over time. Thus, any net benefit may not be achieved in the near term, the long term or at all.

Failure to successfully combine the businesses of AMID and JPE in the expected time frame may adversely affect the future results of the combined company.

The success of the JPE Merger will depend, in part, on our ability to realize the anticipated benefits and synergies from combining the businesses of AMID and JPE. To realize these anticipated benefits, the businesses must be successfully combined. If the combined company is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the JPE Merger may not be realized fully or at all. In addition, the actual integration and the costs associated with operating a larger organization may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the JPE Merger. These difficulties could adversely affect the financial condition and operating results of the combined company.

We or JPE may have difficulty attracting, motivating and retaining executives and other employees in light of the JPE Merger.

Uncertainty about the effect of the JPE Merger on AMID or JPE employees may have an adverse effect on the combined organization. This uncertainty may impair these companies' ability to attract, retain and motivate personnel until the JPE Merger are completed. Employee retention may be particularly challenging during the pendency of the JPE Merger, as employees may feel uncertain about their future roles with the combined organization. In addition, JPE may have to provide additional compensation in order to retain employees. If employees of JPE depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined organization, the combined organization's ability to realize the anticipated benefits of the JPE Merger could be reduced.

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

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations 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 adversely affect our ability to grow our operations and increase our distributions to our unitholders.

If we are unable to make accretive acquisitions from third parties, whether because we are: (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable or attractive terms or (iii) outbid by competitors 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 the cash generated from operations on a per unit basis.

Any acquisition involves potential risks, including, among other things:

- assumptions about volumes, revenue, decline rates, drilling activity and cost savings, including synergies;
- inability to secure adequate customer commitments to use the acquired systems or facilities;
- inability to integrate successfully the assets or businesses we acquire, particularly given the relatively small size of our management team and its limited history with certain assets;
- assumption of unknown liabilities, including environmental contamination;
- limitations on rights to indemnity from the seller;
- assumptions about the overall costs of equity or debt;
- diversion of management's and employees' attention from other business concerns;
- entry of competitors in the markets where the acquired business competes;
- difficulties operating in new geographic areas and business lines; and
- customer or key employee losses at the acquired businesses.

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

Our construction of new assets may not result in increased revenue 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 we intend to grow our business is through organic growth projects. The construction of additions or modifications to our existing systems and the construction of new midstream 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. Cost overruns on construction projects may cause unexpected changes in project economics. Moreover, our revenue 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 revenue until the project is completed and placed into service. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize or only materializes over a period materially longer than expected. Since we are not engaged in the exploration for, and development of, natural gas and crude oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

In addition, the construction of additions to our existing gathering and transportation assets, or the construction of new gathering and transportation assets, may require us to obtain new rights-of-way. We may be unable to obtain such rights-of-way 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 to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases materially, our cash flows could be adversely affected.

In connection with our expansion capital programs, we have agreed, and may in the future agree, to construct oil and gas gathering pipelines to service existing and future oil and gas properties, which involves potential risks.

In connection with our expansion capital programs, we have agreed, and may in the future agree, at our cost and expense, to design, acquire right-of-way for, obtain all permits from governmental authorities for, procure materials for, construct, operate, and maintain additional gathering pipelines for connection to certain current and future producing crude oil and natural gas properties. There are risks involved with such obligations, including:

- general construction cost overruns and delays resulting from numerous factors, many of which may be out of our control;
- the inability to obtain required permits for the pipelines;
- the inability to obtain rights-of-way for the gathering pipelines, which may result in pipelines being re-routed, which itself could result in cost overruns and delays;
- the risk associated with producer’s exploration and production activities and the associated potential failure of the gathering pipelines to generate attractive cash flows given our obligation to construct and operate them; and
- title issues or environmental or regulatory compliance matters or liabilities or accidents associated with the construction or operation of the pipelines.

We currently expect to fund these costs with borrowings under our revolving credit facility or by accessing the capital markets. If we are unable to finance the expansion costs with existing liquidity, we could be required to seek alternative sources of liquidity, which could be costly or may not be available. In the event expansion and extension of the crude oil and natural gas properties is significantly more expensive than we expect or we are unable to obtain financing for such construction, it could have a material adverse effect on our financial condition, including our results of operations and cash flows.

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

We do not intend to obtain independent evaluations of natural gas reserves connected to our systems on a regular or ongoing basis. Accordingly, we may not have independent estimates of total reserves dedicated to some or all of our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering and transportation systems are less than we anticipate and we are unable to secure additional sources of natural gas, 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 business involves many hazards, operational risks and litigation risks, some of which may not be fully covered by insurance. If a significant accident, event or judgment occurs for which we are not adequately insured, our operations and financial results could be adversely affected.

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

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

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. In addition, we have been, and are likely to continue to be, a defendant in various legal proceedings and litigation arising in the ordinary course of business, both as a result of these operating hazards and risks and as a result of other aspects of our business. 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. For example, we do not have any casualty insurance on our underground pipeline systems that would cover damage to the pipelines. We are self-insured for general and product, workers' compensation and automobile liabilities up to predetermined amounts above which third-party insurance applies. Additionally, we do not have business interruption/ loss of income insurance that would provide coverage in the event of damage to any of our underground facilities. 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. We cannot guarantee that our insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage. If a significant accident or event occurs for which we are not fully insured, it could have a material adverse effect on 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, we may be unable to recover from prior owners of our assets, pursuant to our contractual indemnification rights for potential environmental liabilities.

Our interstate natural gas, crude oil and NGL pipelines are subject to regulation by FERC, which could adversely affect our ability to make distributions to our unitholders.

Our AlaTenn and Midla interstate natural gas transportation systems, our Destin pipeline and a portion of our High Point system, are subject to regulation by FERC, under the NGA. Under the NGA, the rates for and terms of conditions of service on these interstate facilities must be just and reasonable and not unduly discriminatory. The rates and terms and conditions for our interstate pipeline services are set forth in tariffs that must be filed with and approved by FERC. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenue associated with providing transportation service.

Under the NGA, FERC has the authority to regulate companies that provide natural gas pipeline transportation services in interstate commerce. FERC's authority over such companies includes such matters as:

- rates, terms and conditions of service;
- the types of services interstate pipelines may offer to their customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

The EP Act 2005 amended the NGA to add an anti-manipulation provision. Pursuant to the amended NGA, FERC established rules prohibiting energy market manipulation. Also, FERC's rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation employees function independently of marketing employees. We are subject to audit by FERC of our compliance in general, including adherence to all its rules and regulations. A violation of these rules, or any other rules, regulations or orders issued or administered by FERC, may subject us to civil penalties, disgorgement of certain profits, or appropriate non-monetary remedies imposed by FERC. In addition, the EP Act 2005 amended the NGA and the NGPA, to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of FERC. The FERC is authorized to impose civil penalties of up to $1,000,000 per violation, per day for violations of the NGA, the NGPA or the rules, regulations, restrictions, conditions and orders promulgated under those statutes. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation.

Additionally, existing rates may not reflect our current costs of operations, which may have risen since the last time our rates were approved by FERC.

Our Bakken crude oil gathering system and our Tri-States and Wilprise NGL pipelines are regulated as common carrier interstate pipelines by the FERC under the ICA, the EP Act 1992, and the rules and regulations promulgated under those laws. FERC regulations require that rates and terms and conditions of service for interstate service pipelines that transport crude oil be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC's regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. Under FERC's regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-services approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

Under the ICA, FERC or interested persons may challenge existing or proposed new or changed rates, services, or terms and conditions of service. FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. FERC could require a common carrier pipeline to collect rates subject to refund until completion of an investigation during which FERC could find that the new or changed rate is unlawful. In contrast, FERC has clarified that initial rates and terms of service agreed upon with committed shippers in a transportation services agreement are not subject to protest or a cost-of-service analysis where the pipeline held an open season offering all potential shippers service on the same terms.

A successful rate challenge could result in a common carrier pipeline paying refunds of revenue collected in excess of the just and reasonable rate, together with interest for the period the rate was in effect, if any. FERC may also order a pipeline to reduce its rates prospectively, and may require a common carrier pipeline to pay shippers reparations retroactively for rate overages for a period of up to two years prior to the filing of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential.

Our intrastate natural gas and gathering transportation and sales services are subject to regulation by state and federal agencies, which could adversely affect our ability to make cash distributions to our unitholders.

Certain of our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers. Such agencies could limit our ability to increase our rates or order us to reduce our rates and pay refunds to shippers. State agencies can also regulate whether a service may be provided or cancelled. If state agencies in the states in which we offer intrastate transportation services change their policies or aggressively regulate our rates or terms and conditions of service, it could also adversely affect our ability to make cash distributions to our unitholders.

Certain of our intrastate natural gas pipelines transport gas in interstate commerce that is subject to FERC jurisdiction under Section 311 of the NGPA or are exempt from FERC jurisdiction as Hinshaw pipelines but have received blanket authorization to transport natural gas on behalf of interstate pipelines. The maximum rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate," as defined in the NGPA. The rates are generally subject to review every five years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations and an inability to make cash distributions to our unitholders.

Intrastate natural gas pipelines, which operate entirely within a single state, are generally not subject to FERC's jurisdiction under the NGA. Hinshaw pipelines operate within a single state but may receive gas from outside their state without becoming subject to FERC jurisdiction under the NGA. Specifically, a Hinshaw pipeline is exempt from FERC's general NGA regulation if: (1) it receives natural gas at or within the boundary of a state; (2) all the gas is consumed within that state; and (3) the pipeline is regulated by a state commission. Hinshaw pipelines may also receive authorization under Part 284, subpart G of the Commission's regulations to transport natural gas on behalf of interstate pipelines or a local distribution company served by an interstate pipeline.

Certain of our pipelines which transport gas in interstate commerce are "Hinshaw" pipelines exempt from the jurisdiction of the FERC jurisdiction under Section 1(c) of the NGA, and we may have additional Hinshaw pipelines in the future. Each of our current Hinshaw pipelines has received a "blanket certificate" under 18 C.F.R. Section 284.244 to transport gas. The maximum rates for services provided the blanket certificate may not exceed a "fair and equitable rate," as defined in the FERC Regulations. The rates are generally subject to review every five years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations and an inability to make cash distributions to our unitholders.

The FERC's anti-manipulation rules apply to non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. As noted above, the FERC's civil penalty authority under the EP Act of 2005 would apply to violations of these rules to the extent applicable to our intrastate natural gas services.

The application of certain FERC policy statements could affect the rate of return on our equity that we are allowed to recover through rates and the amount of any allowance our interstate systems can include for income taxes in establishing their rates for service, which would in turn impact our revenue and/or equity earnings.

FERC currently allows partnerships, including MLPs, to include in their cost-of-service an income tax allowance if the partnership's owners have actual or potential income tax liability, a matter that will be reviewed by FERC on a case-by-case basis. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in United Airlines, Inc., et al. v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline partnership double-recovering the income tax liability of its investors. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. On December 15, 2016, FERC issued a Notice of Inquiry seeking comment on how to address any double recovery resulting from income tax allowance policy. The ultimate outcome of this proceeding is not certain and could result in changes going forward to FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our interstate pipelines could be affected to the extent they propose new rates or changes to their existing rates or if their rates are subject to complaint or challenged by FERC.

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.

Gas gathering facilities and intrastate transportation facilities that do not provide interstate transmission services are exempt from the jurisdiction of FERC under the NGA. In Docket No. CP12-9, the FERC determined that certain portions of our High Point system met the gathering exemption from regulation under the NGA. Although FERC has not made any formal determinations with respect to any of our other facilities, we believe that our gathering and intrastate natural gas pipelines and related facilities that are not engaged in providing interstate transmission services are engaged in exempt gathering and intrastate transportation and, therefore, are not subject to FERC jurisdiction. We believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine if a pipeline is a gathering pipeline and is therefore not subject to FERC's jurisdiction. The distinction between FERC- regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, FERC's policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and intrastate transportation and gathering facilities, on the other, is a fact-based determination made by FERC on a case- by-case basis. If FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by FERC.

Moreover, FERC regulation affects our gathering, transportation and compression business generally. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, capacity release and market transparency and market center promotion, directly and indirectly affect our gathering business. In addition, the classification and regulation of our gathering and intrastate transportation facilities also are 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, nondiscriminatory take requirements and complaint-based rate regulation. We are subject to some state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, 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. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas and crude oil producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

In recent years, FERC's efforts to promote open access, transparency, and the unbundling of interstate pipeline services has prompted a number of interstate pipelines to transfer their non-jurisdictional 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. Such additional scrutiny could result in increased expenses to us and a resulting materially adverse change in our finances.

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

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that restrict the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the Environmental Protection Agency has relied upon as authority for adopting climate change regulatory initiatives;
- the federal CERCLA and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the federal Clean Water Act and analogous state laws that regulate discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the federal Oil Pollution Act of 1990 and analogous state laws that establish strict liability for releases of oil into waters of the United States;
- U.S. Department of the Interior regulations, which relate to offshore oil and natural-gas operations in U.S. waters and impose obligations for establishing financial assurances for decommissioning activities, liabilities for pollution cleanup costs resulting from operations, and potential liabilities for pollution damages;
- the federal Resource Conservation and Recovery Act of 1976 and analogous state laws that impose requirements for the generation, storage, treatment, transport and disposal of solid and hazardous waste from our facilities;
- the Endangered Species Act of 1973 and analogous state laws that restrict activities that may affect federally or state identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- the Toxic Substances Control Act, and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities; and
- the U.S. Occupational Safety and Health Act and analogous state laws that establish workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, the imposition of specific safety and health criteria addressing worker protection, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations. Numerous governmental authorities, such as the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial 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 or delay expansion projects and limit our growth and revenue. Please read “Business - Environmental Matters - Air Quality and Climate Control” for more information about these matters.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbons and other wastes and potential emissions and discharges related to our operations. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbons and other wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our hydrocarbons and other 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 or natural resource 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 damage and fines or penalties for related violations of environmental laws or regulations. We may not be able to recover all or any of these costs from insurance. In addition, changes in environmental laws and regulations 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 results of operations or financial position. Please read “Business - Environmental Matters” for more information.

We may be unable to obtain or renew permits necessary for our operations or the operations we may acquire in future acquisitions.

Our facilities operate under a number of required federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approvals, limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval, limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay issuing a new or renewed material permit, license or approval, or to revoke or substantially modify an existing permit, license or approval, could have a material adverse effect on our financial condition, including our results of operations and cash flows.

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

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

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

We do not own all of the land on which our 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 such rights-of-way lapse or terminate or do not allow us to change our operations, or we may not be able to renew our contract leases on commercially reasonable terms or at all. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time for specific types of operations. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise or our inability to amend these rights for new operations, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

A shortage of skilled labor in the midstream 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 crude oil requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our general partner's employees, our results of operations could be materially and adversely affected.

Our work force could become unionized in the future, which could adversely affect the stability of our production and materially reduce our profitability.

Substantially all of our systems are operated by non-union employees. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could adversely affect the stability of our operations and materially reduce our profitability.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may adversely affect our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings or downtime, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operational departments, and these systems may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber-attacks on our customer and employee data may result in financial loss and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

Terrorist attacks, the threat of terrorist attacks, and sustained military campaigns may adversely impact our results of operations.

Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East and North Africa or other sustained military conflicts may affect our operations in unpredictable ways, including disruptions of crude oil supplies or storage facilities, and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Risks Related to Our Units, Partnership Structure and Ownership

Master limited partnerships (“MLPs”) do not have the same flexibility as other types of organizations to accumulate cash. This may limit cash available to make distributions to our unitholders.

Subject to the limitations on restricted payments in the indenture governing the notes and in our revolving credit facility and any future indebtedness we may incur, we are required by our partnership agreement to distribute all of our “available cash” each quarter to our limited partners and our general partner. Available cash is defined in our partnership agreement and 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 our general partner to:

- provide for the proper conduct of our business (including reserves for future capital expenditures, for anticipated future credit needs subsequent to that quarter, for legal matters and for refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceeding);
- comply with applicable law or regulation, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our 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 our general partner so determines, all or any portion of the cash on hand on the date of distribution of available cash for the quarter, including cash on hand resulting from working capital borrowings made subsequent to the end of such quarter.

As a result, we do not accumulate significant amounts of cash and thus do not have the same flexibility as corporations or other entities that do not pay dividends or have complete flexibility regarding the amounts they will distribute to their equity holders. The timing and amount of our distributions could significantly reduce the cash available to pay the principal, premium (if any) and interest on the notes. The board of directors of our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating subsidiaries as it determines are necessary or appropriate.

Although our payment obligations to our unitholders are subordinate to our payment obligations with respect to the notes, we expect that the value of our units would decrease if we decrease the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize and our ability to service our indebtedness, including the notes, may be materially impaired.

We may not have sufficient cash from operations to enable us to pay distributions to holders of our common units.

We may not have sufficient available cash from operations each quarter to enable us to pay the minimum quarterly distribution of $0.4125 per common unit or at all. These distributions may only be made from cash available for distribution after the preferred quarterly distribution to which our Convertible Preferred Units are entitled, the establishment of cash reserves, and payment of our fees and expenses. 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:

- the volume of natural gas we gather, process and transport;
- the level of production of crude oil and natural gas and the resultant market prices of crude oil and natural gas and NGLs;
- realized pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- changes in the fees we charge for our services;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- the effect of seasonal variations in temperature on the amount of natural gas and crude oil that we transport and the amount of natural gas that we store, process and treat;
- capacity charges and volumetric fees associated with our transportation services;
- storage capacity utilization associated with our terminals segment;
- the level of competition from other midstream energy companies in our geographic markets;
- the creditworthiness of our customers;
- the level of our operating, maintenance and corporate costs;
- regulatory action affecting the supply of, or demand for, natural gas, the transportation rates we can charge on our regulated pipelines, how we contract for services, our existing contracts, our operating costs and our operating flexibility; and
- acts of God.

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

- the level and timing of capital expenditures we make;
- the cost of acquisitions, and the resulting costs of integrations, if any;
- our debt service payments and requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our Credit Agreement;
- the amount of cash reserves established by our General Partner; and
- other business risks affecting our cash levels.

There is no guarantee that unitholders will receive quarterly distributions from us. Our distributions are determined each quarter by the Board of Directors of our General Partner based on the board's consideration of the foregoing factors, our financial position, earnings, cash flow, current and future business needs and other relevant factors at that time. We may reduce or eliminate distributions at any time we have insufficient cash available for distributions. This may be due to insufficient cash reserves, requirements to fund current or anticipated future operations, capital expenditures, acquisitions, growth or expansion projects, debt repayment or other business needs.

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 net losses for financial reporting purposes and may not make cash distributions during periods when we record net income for financial reporting purposes.

We have a holding company structure in which our subsidiaries and unconsolidated affiliates conduct our operations and own our operating assets, and our ability to make cash distributions depends on the performance of these entities and their ability to distribute funds to us.

We are a holding company, and our subsidiaries and unconsolidated affiliates conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and unconsolidated affiliates. As a result, our ability to make distributions depends on the performance of our subsidiaries and these other entities and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, our revolving credit facility, the terms of debt and other agreements to which they are a party, their organizational documents and applicable state corporation, limited liability company, limited partnership or similar statutes and other laws and regulations. Moreover, we are a minority owner in several of our unconsolidated affiliates and may not possess the power to cause those entities to make distributions of cash to us. We cannot assure you that the earnings from, or other available assets of, our subsidiaries and other unconsolidated affiliates will be sufficient to enable us to make cash distributions.

As our common units are yield-oriented securities, increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates have increased recently and may continue to increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Affiliates of ArcLight directly own our general partner, which has sole responsibility for conducting our business and managing our operations. These affiliates elect all of the members of the board of our general partner. These affiliates and our general partner have conflicts of interest with us and limited fiduciary duties, and they may favor their own interests to the detriment of us and our unitholders.

Affiliates of ArcLight and our general partner have the power to appoint all of the officers and directors of our general partner. The directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to it, and have no duty to us or our common unitholders. Conflicts of interest may arise between these affiliates and our general partner, on the one hand, and us and our noteholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of these affiliates over our interests and the interests of our noteholders. These conflicts include the following situations, among others:

- neither our Partnership Agreement nor any other agreement requires these affiliates of ArcLight to pursue a business strategy that favors us, and the officers and directors of these affiliates may have a fiduciary duty to make these decisions in the best interests of these affiliates of ArcLight and their respective direct and indirect owners, respectively, which may be contrary to our interests. These affiliates of ArcLight may choose to shift the focus of their investment and growth to areas not served by our assets;
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These affiliates of ArcLight, their respective direct and indirect owners and their respective affiliates are not limited in their ability to compete with us and may offer business opportunities or sell midstream assets to third parties without first offering us the right to bid for them;

- our general partner is allowed to take into account the interests of parties other than us in resolving conflicts of interest and exercising certain rights under our Partnership Agreement, which has the effect of limiting its duty to our unitholders;
- our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limits our general partner’s liabilities, and also restricts the remedies available to our noteholders for actions that, without the limitations, might constitute breaches of such fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- disputes may arise under our commercial agreements or acquisition agreements with these affiliates of ArcLight;

- 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 as well as the conversion of the Convertible Preferred Units into 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 Convertible Preferred Units, to make incentive distributions or to accelerate the expiration of a subordination period;
- our Partnership Agreement permits us to classify up to $11.5 million as operating surplus, even if it is generated from asset sales, nonworking capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our Convertible Preferred Units or to our general partner in respect of the general partner interest or the incentive distribution rights;
- our Partnership Agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our general partner controls the enforcement of the obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- our general partner may transfer its IDRs without unitholder approval; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner’s incentive distribution rights without the approval of the Conflicts Committee of the Board of Directors of our general partner (“Conflicts Committee”) or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

The affiliates of ArcLight that own our general partner are not limited in their ability to compete with us and are not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

The affiliates of ArcLight that own our general partner are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, affiliates of our general partner and the entities owned or controlled by affiliates of our general partner, including these affiliates of ArcLight may acquire, construct or dispose of additional midstream 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. Moreover, while these affiliates of ArcLight may offer us the opportunity to buy additional assets from them, they are under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed. This may create actual and potential conflicts of interest between us and affiliates of our general partner, and result in less than favorable treatment of us and our unitholders.

The New York Stock Exchange (“NYSE”) does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded 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. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

If you are not an eligible holder, you may not receive distributions or allocations of income or loss on your common units and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity’s owners are U.S. individuals or entities subject to such taxation. If you are not an eligible holder, our General Partner may elect not to make distributions or allocate net income or loss on your units, and you run the risk of having your units redeemed by us at the lower of your purchase price for the units and the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our General Partner.

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 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 partnership agreement requires that we distribute our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires us to distribute our available cash to our unitholders. Accordingly, we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to distribute our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, or 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 indebtedness 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 general partner may limit its liability regarding our obligations.

Our general partner may 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 permits our general partner to limit its liability, 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 our ability to make cash distributions to our unitholders.

Our Partnership Agreement limits our General Partner’s fiduciary duties to us and the holders of our common units.

Our Partnership Agreement contains provisions that modify and reduce the fiduciary duties 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.

50

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Our Partnership Agreement restricts the remedies available to holders of our common 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, or not opposed to, the best interest of our partnership;
- 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:

a. 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;
b. approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates;
c. on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
d. fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our General Partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the Conflicts Committee, and the Board of Directors of our General Partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) 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.

Our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our General Partner's incentive distribution rights without the approval of the Conflicts Committee of our General Partner's board or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our General Partner has the right, at any time it has received incentive distributions exceeding the target distribution described in our Partnership Agreement 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 our General Partner, 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 our General Partner 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 our General Partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our General Partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our General Partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the General Partner 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 our General Partner in connection with resetting the target distribution levels related to our General Partner's incentive distribution rights.

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The Board of Directors of our General Partner will be chosen by HPIP. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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

Our unitholders are unable to remove our General Partner without its consent because our General Partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. As of March 20, 2017, ArcLight indirectly held common units or convertible preferred units representing 49.2% of our then-outstanding common units.

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

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

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

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

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our Partnership Agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders’ proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because of the Series A 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.

ArcLight 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.

As of March 20, 2017, ArcLight held 7,187,358 Series A-1 Units, 3,079,284 Series A-2 Units, 8,792,205 Series C Units and 2,333,333 Series D Units through its affiliates. The Series A-1, A-2, C and D Units are all convertible into common units at the election of ArcLight at any time. In addition, as of March 20, 2017, ArcLight indirectly held 13,977,709 common units, including 1,349,609 common units held by our General Partner, which ArcLight controls. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our General Partner and its affiliates own more than 80% of our 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, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A General Partner of a partnership generally has unlimited liability for the obligations of the Partnership, except for those contractual obligations of the Partnership that are expressly made without recourse to the General Partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a General Partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- your 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 you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the Partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the Partnership are counted for purposes of determining whether a distribution is permitted.

If we are deemed an “investment company” under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include 20.1% non-operated interest in Delta House Class A Units, a 16.7% non-operated interest in Tri-States, a 25.3% non-operated interest in Wilprise, a non-operated interest in Mesquite and a 26.3% non- operated interest in Pinto, any of which may be deemed to be an “investment security” within the meaning of the Investment

Company Act of 1940, as amended (the “Investment Company Act”). In the future, we may acquire additional minority owned interests that could be deemed “investment securities.” If a sufficient amount of our assets are deemed to be “investment securities” within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business. Moreover, treatment of us as an investment company would prevent our qualification as a partnership for U.S. federal income tax purposes in which case we would be treated as a corporation for U.S. federal income tax purposes, and be subject to U.S. federal income tax at the corporate tax rate, significantly reducing the cash available for distributions.

Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") treats us as a corporation for U.S. federal income tax purposes or we become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to the unitholders 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 U.S. 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 publicly traded partnership such as ours to be treated as a corporation rather than a partnership for U.S. federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, the IRS could disagree with the positions we take or 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 U.S. 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%, and would likely pay state income tax at varying rates. Distributions to a unitholder 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 the unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation for U.S. federal income tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to the 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.

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

The present 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 interpretation at any time. From time to time, members of the U.S. Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. If successful, such proposals or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

On January 24, 2017, the U.S. Treasury Department and the IRS published final regulations (the “Final Regulations”) regarding qualifying income under Section 7704(d)(1)(E) of the Code. The Final Regulations treat as qualifying income the income earned from retail sales of propane. We do not believe the Final Regulations adversely affect our ability to qualify as a
partnership for U.S. federal income tax purposes.

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. For example, we are required to pay the State of Texas a margin tax that is assessed at 0.75% of taxable margin apportioned to Texas. Imposition of such a tax on us by any state will reduce the cash available for distribution to unitholders. The 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 levels will be adjusted to reflect the impact of that law on us.

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

We are subject to extensive tax laws and regulations, including federal and state income tax laws and transactional tax laws such as excise, sales/use, payroll, franchise and ad valorem tax laws. 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. Further, taxing authorities may change their application of existing taxes, so that additional entities or transactions may become subject to an existing tax. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional tax payments, as well as interest and penalties. The costs of these audits are borne indirectly by the unitholders and our General Partner because such costs reduce our cash available for distribution.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS, and the outcome of any such contest, may increase a unitholder's tax liability and result in adjustment to items unrelated to us and could materially and adversely impact the market for our common units and the price at which they trade. The rights of a unitholder owning less than a 1% profits interest in us to participate in the U.S. federal income tax audit process are very limited. In addition, our costs of any contest with the IRS will be borne indirectly by the unitholders and our General Partner because such costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our General Partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to (or will choose to) do so under all circumstances, or that we will be able to (or will choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

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

Because a unitholder will be treated as a partner to whom we will allocate taxable income, which could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of U.S. federal income taxes and, in some cases, state and local income taxes on its share of our taxable income even if it receives no cash distributions from us. The unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Certain actions that we may take, such as issuing additional units, may increase the U.S. federal income tax liability of unitholders.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder's share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder's units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder's tax basis in its units.

In addition, the U.S. federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for U.S. federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to the our assets.

There are limits on the deductibility of losses that may adversely affect unitholders.

In the case of taxpayers subject to the passive loss rules (generally, individuals, closely-held corporations and regulated investment companies), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of the unitholder’s entire investment in us in a fully taxable transaction with an unrelated party. A unitholder’s share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships.

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

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

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

Investment in common units by tax-exempt entities, such as individual retirement accounts, or IRAs, other retirement plans 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, which may be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the 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 the 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 the 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. Treasury recently adopted final regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders to ours. These regulations apply to certain publicly-traded partnerships, including us, for taxable years beginning on or after August 3, 2015. However, these regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among the unitholders.

A unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and such unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those 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. Therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their common units.

We have adopted certain valuation methodologies for tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to the unitholders. It also could affect the amount of gain from the unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the 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 U.S. federal income tax purposes.

We will be considered to have terminated as a partnership for U.S. 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 termination, among other things, would 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 from the IRS were not granted, as described below) for one fiscal year and could also 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 calendar year, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Under current law, such a termination would not affect our classification as a partnership for U.S. federal income tax purposes, but instead, after our termination, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has announced a relief procedure for publicly traded partnerships that terminate in this manner, whereby, if a publicly traded partnership that has terminated requests and the IRS grants special relief, among other things, such partnership would only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years resulting from the termination.

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not reside as a result of investing in our units.

In addition to U.S. federal income taxes, unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder's responsibility to file all U.S. federal, foreign, state, local and non-U.S. tax returns.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

A description of our properties is contained in "Item 1. Business" of this Annual Report and is incorporated into this Item 2. by reference.

Our principal executive offices are located at 2103 CityWest Blvd., Bldg. 4, Suite 800, Houston, Texas 77042 and our telephone number is 346-241-3400.

Item 3. Legal Proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate impact of any proceedings cannot be predicted with certainly, our management believes that the resolution of any of our pending proceeds will not have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

Our common units have been listed on the New York Stock Exchange ("NYSE") since July 27, 2011, under the symbol "AMID." The following table sets forth the high and low sales prices of our common units, as reported by the NYSE for each quarter during 2016 and 2015, together with distributions paid subsequent to such quarter for that quarter through December 31, 2016:

Period Ended	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2016				
High Price	$18.30	$15.19	$14.00	$8.49
Low Price	$13.06	$10.39	$6.18	$4.03
Distribution per common unit	$0.4125	$0.4125	$0.4125	$0.4125
2015				
High Price	$12.70	$16.71	$19.42	$21.17
Low Price	$3.80	$9.01	$15.75	$15.71
Distribution per common unit	$0.4725	$0.4725	$0.4725	$0.4725

As of March 20, 2017, there were 206 unitholders of record of our 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 approximately 10,266,642 Series A Units, 8,792,205 Series C Units, 2,333,333 Series D Units and 933,435 General Partner units, for which there is no established trading market. Our General Partner and its affiliates receive quarterly distributions on the General Partner units only after the requisite distributions have been paid on the common units and Series A Units, Series C Units, and Series D Units.

Our Distribution Policy

Our Partnership Agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects our belief that our unitholders will be better served if we distribute rather than retain our available cash. Generally, our available cash is the sum of our i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and ii) cash on hand resulting from working capital borrowings made after the end of the quarter. We pay the cash dividend in one payment to those unitholders of record on the applicable record date, as determined by the General Partner.

The following table sets forth the number of units at December 31, 2016 and 2015 (in thousands):

	December 31, 2016	December 31, 2015
Series A convertible preferred units	10,107	9,210
Series B convertible units (1)	—	1,350
Series C convertible preferred units	8,792	—
Series D convertible preferred units	2,333	—
Limited partner common units	31,237	30,427
General Partner units	680	536

(1) Our General Partner held 1,349,609 Series B convertible units ("Series B Units"), which converted into common units on a one-for-one basis on February 1, 2016.

Our General Partner's initial 2.0% interest in distributions has been reduced to 1.3% due to the issuance of additional units and the General Partner has not contributed a proportionate amount of capital to us to maintain its initial 2.0% General Partner notional interest.

Our cash distribution policy, as expressed in our Partnership Agreement, may not be modified or repealed without amending our Partnership Agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our General Partner establishes in accordance with our Partnership Agreement as described above. We will pay our distributions on or about the 15th of each February, May, August and November to holders of record on or about the 5th of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date.

Series A Units

Distributions on Series A Units can be made with paid-in-kind Series A Units, cash or a combination thereof, at the discretion of the Board of Directors, which began with the distribution for the three months ended June 30, 2014 and continued through the distribution for the quarter ended March 31, 2016. At December 31, 2016, we accrued $2.5 million of contractual cash distributions on the Series A Units which were paid in February 2017.

Series C Units

Distributions on Series C Units can be made with paid-in-kind Series C Units, cash or a combination thereof, at the discretion of the Board of Directors. At December 31, 2016, we accrued $3.6 million of contractual cash distributions on the Series C Units which were paid in February 2017.

Series D Units

Distributions on Series D Units are equal to the greater of $0.4125 and the cash distribution that the Series D Units would have received if they had been converted to common units immediately prior to the beginning of the quarter. At December 31, 2016, we accrued $1.0 million of contractual cash distributions on the Series D Units which were paid in February 2017.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2016:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	275,000	$ 9.03	5,017,528
Total	275,000	9.03	5,017,528

Item 6. Selected Historical Financial and Operating Data

The following table presents selected historical consolidated financial and operating data for the periods and as of the dates indicated. We derived this information from our historical consolidated financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those consolidated financial statements and notes, which for the years 2016, 2015, and 2014 begin on F-1 to this Annual Report.

For a detailed discussion of the following table, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Years ended December 31,				
	2016 (1)	2015 (1)	2014 (1)	2013 (1)	2012
	(in thousands, except per unit and operating data)				
Statements of Operations Data:					
Revenues:					
Sales of natural gas, NGLs and condensate	$160,950	$179,818	$255,025	$241,401	$192,968
Services	72,572	55,216	52,284	52,650	14,308
Gain (loss) on commodity derivatives, net	(840)	1,324	1,091	28	992
Total revenue	232,682	236,358	308,400	294,079	208,268
Operating expenses:					
Purchases of natural gas, NGLs and condensate	92,556	105,883	197,952	215,053	154,472
Direct operating expenses	61,861	60,737	45,919	32,275	17,223
Corporate expenses	54,223	29,818	24,422	21,134	16,052
Depreciation, amortization and accretion expense	46,022	38,014	28,832	30,002	21,287
(Gain) loss on involuntary conversion of property, plant and equipment	—	—	—	(343)	1,021
(Gain) loss on sale of assets, net	591	3,011	122	—	(123)
Loss on impairment of property, plant and equipment	697	—	99,892	18,155	—
Loss on impairment of goodwill	—	118,592	—	—	—
Total operating expenses	255,950	356,055	397,139	316,276	209,932
Operating loss	(23,268)	(119,697)	(88,739)	(22,197)	(1,664)
Other income (expense):					
Interest expense	(15,499)	(14,745)	(7,577)	(9,291)	(4,570)
Other expense	—	—	(670)	—	—
Earnings in unconsolidated affiliates	40,158	8,201	348	—	—
Income (loss) from continuing operations before income taxes	1,391	(126,241)	(96,638)	(31,488)	(6,234)
Income tax (expense) benefit	(2,057)	(1,134)	(557)	495	—
Income (loss) from continuing operations	(666)	(127,375)	(97,195)	(30,993)	(6,234)
Discontinued operations:					
Loss from discontinued operations, net of tax	—	(80)	(611)	(2,413)	(18)
Net loss	(666)	(127,455)	(97,806)	(33,406)	(6,252)
Net income attributable to non-controlling interests	2,804	25	214	633	256
Net loss attributable to the Partnership	$(3,470)	$(127,480)	$(98,020)	$(34,039)	$(6,508)
General Partner's Interest in net loss	$(48)	$(1,645)	$(1,279)	$(1,405)	$(129)
Limited Partners' Interest in net loss	$(3,422)	$(125,835)	$(96,741)	$(32,634)	$(6,379)

Limited Partners' net (loss) per common unit:
Basic and diluted:

65

Loss from continuing operations	$(1.11)	$(6.00)	$(8.54)	$(7.15)	$(0.70)
Loss from discontinued operations	—	—	(0.04)	(0.27)	—
Net loss	$(1.11)	$(6.00)	$(8.58)	$(7.42)	$(0.70)
Weighted average number of common units outstanding:					
Basic and diluted (2)	31,043	24,983	13,472	7,525	9,113
Statement of Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$45,362	$40,937	$21,478	$17,223	$18,348
Investing activities	(551,441)	(171,692)	(471,870)	(28,214)	(62,427)
Financing activities	509,018	130,256	450,490	10,816	43,784
Other Financial Data:					
Adjusted EBITDA (3)	$132,023	$66,311	$45,551	$31,907	$18,850
Gross margin (4)	130,065	122,201	102,655	74,821	49,431
Cash distribution declared per common unit	1.71	1.89	1.85	1.75	1.73
Segment gross margin:					
Gathering and Processing	74,582	76,865	50,817	36,985	36,118
Transmission	41,233	35,301	42,828	32,408	13,313
Terminals	14,250	10,035	9,010	5,428	—
Balance Sheet Data (at period end):					
Cash and cash equivalents	$2,939	$—	$499	$393	$576
Accounts receivable and unbilled revenue	29,322	18,740	29,543	29,823	23,470
Property, plant and equipment, net	755,457	655,310	582,182	312,701	223,819
Investments in unconsolidated affiliates	291,987	63,704	22,252	—	—
Restricted cash	323,564	5,037	5,037	3,000	—
Total assets	1,563,495	891,880	913,558	382,075	256,696
Current portion of long-term debt	4,458	2,338	2,908	2,048	—
Long-term debt	711,250	525,100	372,950	130,735	128,285
Operating Data:					
Gathering and processing segment:					
Average throughput (MMcf/d)	393.7	338.2	274.8	277.2	291.2
Average plant inlet volume (MMcf/d) (5)	102.1	120.9	89.1	117.3	116.1
Average gross NGL production (Mgal/d) (5)	192.9	231.1	64.2	52.0	49.9
Average gross condensate production (Mgal/d) (5)	86.6	99.8	75.2	46.2	22.6
Transmission segment:					
Average throughput (MMcf/d)	683.2	708.6	778.9	644.7	398.5
Average firm transportation - capacity reservation (MMcf/d)	688.1	653.7	577.9	640.7	703.6
Average interruptible transportation - throughput (MMcf/d)	354.0	410.3	468.9	389.2	86.6
Terminals segment:					
Storage utilization	92.5 %	88.1 %	91.4 %	95.6 %	— %

(1) During these years, we had the following transactions that affect comparability: i) in October 2016 and April 2016 we acquired a 6.2% and a 1% non-operated interest in Delta House Class A Units, respectively; ii) in April 2016, we acquired

membership interests in Destin (49.7%), Tri-States (16.7%), Okeanos (66.7%), and Wilprise (25.3%), which we account for as equity method investments; iii) in April 2016 we acquired a 60% interest in American Panther which we consolidate for financial reporting purposes; iv) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House Class A Units, which we account for as an equity method investment; and v) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which are included in our Gathering and Processing segment. vi) in December 2013, we acquired Blackwater, which is included in our Terminals segment; and vii) in April 2013, we acquired the High Point System, which is included in Transmission segment.

(2) Includes unvested phantom units with distribution equivalent rights ("DERs"), which are considered participating securities, of 200,000 at December 31, 2016 and 2015.

(3) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read "Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations."

(4) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use gross margin to evaluate our operating performance, please read "Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations."

(5) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, please read "Item 7. Management's Discussion and Analysis — Our Operations - Gathering and Processing Segment"

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the audited consolidated financial statements and the related notes thereto included elsewhere in this Annual Report. This discussion contains forward-looking statements that reflect management’s current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements or as a result of certain factors such as those set forth below under the caption "Cautionary Statement About Forward-Looking Statements."

Overview

We are a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We provide critical midstream infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. Through our three financial reporting segments, (i) gathering and processing, (ii) transmission and (iii) terminals, we engage in the business of gathering, treating, processing, and transporting natural gas; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products.

Our primary assets are strategically located in some of the most prolific onshore and offshore producing regions and key demand markets in the United States. Our gathering and processing assets are primarily located in (i) the Permian Basin of West Texas, (ii) the Cotton Valley/Haynesville Shale of East Texas, (iii) the Eagle Ford Shale of South Texas, (iv) the Bakken Shale of North Dakota, and (v) offshore in the Gulf of Mexico. Our transmission and terminal assets are located in key demand markets in Alabama, Louisiana, Mississippi and Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia.

We own or have ownership interests in more than 3,800 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 15 gathering systems, six interstate pipelines and eight intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 80 MMBbl/d of crude oil and 200 MMcf/d of natural gas; and three marine terminal sites with approximately 2.4 MMBbls of above-ground aggregate storage capacity for petroleum products, distillates, chemicals and agricultural products.

A portion of our cash flow is derived from our investments in unconsolidated affiliates including a 49.7% operated interest in Destin, a natural gas pipeline; a 20.1% non-operated interest in the Class A Units of Delta House, which is a floating production system platform and related pipeline infrastructure; a 16.7% non-operated interest in Tri-States, an NGL pipeline; a 66.7% operated interest in Okeanos, a natural gas pipeline; a 25.3% non-operated interest in Wilprise, a NGL pipeline; and a 66.7% non-operated interest in MPOG, a crude oil gathering and processing system.

Significant financial highlights during the year ended December 31, 2016, include the following:

- Net loss attributable to the Partnership decreased by $124.0 million for the year ended December 31, 2016 as compared to the same periods in 2015, primarily due to the loss on impairment of goodwill of $118.6 million recognized in 2015 and an increase in earnings in unconsolidated affiliates of $32.0 million primarily from our investments in Delta House and the entities underlying the Emerald Transactions, offset by an increase in corporate expense of $24.4 million due to our corporate relocation and JPE Merger expenses;

- On March 8, 2017, we completed the acquisition of JPE, which resulted in a larger and more diversified midstream business;

- On December 28, 2016, we completed the issuance of the 8.50% Senior Notes which provided net proceeds of approximately $291.3 million after deducting issuances costs;

- On October 31, 2016, we acquired an additional 6.2% non-operated direct interest in Delta House Class A Units for a purchase price of approximately $48.8 million, which was funded with net proceeds of $34.5 million from the issuance of 2,333,333 Series D Units plus $14.3 million of additional borrowings under our Credit Agreement. If any Series D Units remain outstanding on June 30, 2017, the Partnership will issue the Series D unitholders a warrant to purchase up to 700,000 common units at an exercise price of $22.00 per common unit;

- On September 30, 2016, we completed the issuance of the 3.77% Senior Notes, which provided net proceeds of approximately $57.7 million after deducting related issuance costs;

- On April 25, 2016 and April 27, 2016, we acquired a 16.7% non-operated interest in Tri-States, an NGL pipeline; a 66.7% operated interest in Okeanos, a natural gas pipeline; and a 25.3% non-operated interest Wilprise, an NGL pipeline for $211 million. We funded the aggregate purchase price with the issuance of 8,571,429 Series C Units representing limited partnership interests in the Partnership and a warrant to purchase up to 800,000 common units at an exercise price of $7.25 per common unit with a combined value of approximately $120.0 million, plus additional borrowings of $91.0 million under our Credit Agreement;

- On April 25, 2016, the Partnership increased its investment in Delta House through the purchase of 100% of the outstanding membership interests in D-Day, which owned 1.0% of Delta House Class A Units in exchange for approximately $9.9 million;

- Earnings in unconsolidated affiliates were $40.2 million in 2016, an increase of $32.0 million from 2015 primarily due to incremental earnings related to our investments in Delta House and in the interests in the entities underlying the Emerald Transactions;

- Adjusted gross margin increased by $7.9 million, or an increase of 6.5%, as compared to the same period in 2015 primarily attributable to an increase in segment gross margin in our Transmission segment of $5.9 million due to the Pascagoula plant shutdown. The Pascagoula plant is not controlled or owned by the Partnership. As a result of the Pascagoula plant shutdown, volumes were redirected to our High Point system. Our Terminals segment gross margin also increased by $4.3 million as a result of higher storage revenue. These increases were partially offset by a decrease in segment gross margin in our Gathering and Processing segment of $2.3 million as a result of lower NGL and condensate production.

- Adjusted EBITDA increased by $65.7 million, or an increase of 99.1%, as compared to the same period in 2015 primarily due to distribution from our investments in Delta House and entities underlying the Emerald Transactions; and

- We distributed $53.5 million to our Limited Partner common unitholders, or $1.71 per common unit;

Significant operational highlights during the year ended December 31, 2016, include the following:

- The percentage of gross margin generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts increased to 88.9% compared to 85.7% for 2015;

- Average gross condensate production totaled 86.6 Mgal/d, representing a 13.2 Mgal/d or 13.2% decrease compared to 2015 due to lower condensate prices of 11.3%;

- Throughput volumes attributable to the Partnership totaled 1,076.9 MMcf/d, representing a 2.9% increase compared to 2015 due to the Pascagoula plant shutdown, which redirected volumes to our High Point system;
- Contracted capacity for our Terminals segment averaged 2,011,133 barrels, representing a 35.2% increase compared to 2015 due to the expansion efforts at our Harvey terminal; and
- Average gross NGL production totaled 192.9 Mgal/d, representing a 38.2 Mgal/d or 16.5% decrease compared to 2015.

Our Operations

We manage our business and analyze and report our results of operations through three business segments:

- Gathering and Processing. Our Gathering and Processing segment provides "wellhead-to-market" services to producers of natural gas and crude oil, which include transporting raw natural gas and crude oil from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs, and selling or delivering pipeline-quality natural gas, crude oil, and NGLs to various markets and pipeline systems.
- Transmission. Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, which include local distribution companies ("LDCs"), utilities and industrial, commercial and power generation customers.
- Terminals. Our Terminals segment provides above-ground leasable storage operations at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products.

Gathering and Processing Segment

Our results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas and crude oil we gather, process and fractionate, the commercial terms in our current contract portfolio and natural gas, crude oil, NGL, and condensate prices. We gather and process natural gas and crude oil primarily pursuant to the following arrangements:

- Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed fee for gathering, processing and transporting natural gas and crude oil.
- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas and off-spec condensate from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas or off-spec condensate at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas or off-spec condensate, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.
- Percent-of-Proceeds Arrangements ("POP"). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas, NGLs and condensate at market prices. Where we provide processing services at the processing plants that we own, or obtain processing services for our own account in connection with our elective processing

arrangements, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas. Our POP arrangements also often contain a fee-based component.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas and crude oil that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in throughput volumes from producers and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows, but upside in higher commodity-price environments is limited to an increase in throughput volumes from producers. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements also often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. Please read "Item 7A — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

Transmission Segment

Results of operations from our Transmission segment are determined by capacity reservation fees from firm transportation contracts and the volumes of natural gas transported on the interstate and intrastate pipelines we own pursuant to interruptible transportation or fixed-margin contracts. Our transportation arrangements are further described below:

- Firm Transportation Arrangements. Our obligation to provide firm transportation service means that we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable-use charge with respect to quantities actually transported by us.

- Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper to the extent that we have available capacity. For this service, the shipper pays no reservation charge but pays a variable-use charge for quantities actually shipped.

- Fixed-Margin Arrangements. Under these arrangements, we purchase natural gas from producers or suppliers at receipt points on our systems at an index price less a fixed transportation fee and simultaneously sell an identical volume of natural gas at delivery points on our systems at the same undiscounted index price. We view fixed-margin arrangements to be economically equivalent to our interruptible transportation arrangements.

Terminals Segment

Our Terminals segment provides above-ground leasable storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including petroleum products, distillates, chemicals and agricultural products. We generally receive fee-based compensation on guaranteed firm storage contracts, throughput fees charged to our customers when their products are either received or disbursed and other fee-based charges associated with ancillary services provided to our customers, such as excess throughput and truck weighing. Our firm storage contracts are typically multi-year contracts with renewal options.

Contract Mix

For the years ended December 31, 2016, 2015, and 2014, $115.6 million, $104.7 million, and $76.4 million, or 88.9%, 85.7%, and 74.4%, respectively, of our gross margin was generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts.

Set forth below is a table summarizing our average contract mix relative to segment gross margin for the years ended December 31, 2016, 2015, and 2014 (in thousands):

	For the Year Ended December 31, 2016			For the Year Ended December 31, 2015			For the Year Ended December 31, 2014		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gathering and Processing									
Fee-based	$51,834	69.5	%	$40,278	52.4	%	$21,394	42.1	%
Fixed margin	8,279	11.1	%	19,139	24.9	%	3,151	6.2	%
Percent-of-proceeds	14,469	19.4	%	17,448	22.7	%	26,272	51.7	%
Total	$74,582	100.0	%	$76,865	100.0	%	$50,817	100.0	%
Transmission									
Firm transportation	$17,648	42.8	%	$10,767	30.5	%	$11,092	25.9	%
Interruptible transportation	23,585	57.2	%	24,534	69.5	%	31,736	74.1	%
Total	$41,233	100.0	%	$35,301	100.0	%	$42,828	100.0	%
Terminals									
Firm storage	$14,250	100.0	%	$10,035	100.0	%	$9,010	100.0	%
Total	$14,250	100.0	%	$10,035	100.0	%	$9,010	100.0	%

Cash distributions derived from our unconsolidated affiliates amounted to $83.0 million and $20.6 million for the years ended December 31, 2016 and 2015, respectively, and are primarily generated from fee-based gathering and processing arrangements.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics include throughput volumes, storage utilization, segment gross margin, gross margin, operating margin, direct operating expenses on a segment basis, and Adjusted EBITDA on a company-wide basis.

Throughput Volumes

In our Gathering and Processing segment, we must continually obtain new supplies of natural gas, crude oil, NGLs and condensate to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes of natural gas, crude oil, NGLs and condensate is impacted by i) the level of work-overs or recompletions of existing connected wells and successful drilling activity of our significant producers in areas currently dedicated to or near our gathering systems, ii) our ability to compete for volumes from successful new wells in the areas in which we operate, iii) our ability to obtain natural gas, crude oil, NGLs and condensate that has been released from other commitments and iv) the volume of natural gas, crude oil, NGLs and condensate that we purchase from connected systems. We actively monitor producer activity in the areas served by our gathering and processing systems to maintain current throughput volumes and pursue new supply opportunities.

In our Transmission segment, the majority of our segment gross margin is generated by firm capacity reservation charges and interruptible transportation services from throughput volumes on our interstate and intrastate pipelines. Substantially all of our Transmission segment gross margin is generated under contracts with shippers, including producers, industrial companies, LDCs and marketers, for firm and interruptible natural gas transportation on our pipelines. We routinely monitor natural gas market activities in the areas served by our transmission systems to maintain current throughput volumes and pursue new shipper opportunities.

In our Terminals segment, we generally receive fee-based compensation on guaranteed firm storage contracts, throughput fees charged to our customers when their products are either received or disbursed, and other operational charges associated with ancillary services provided to our customers, such as excess throughput, steam heating and truck weighing.

Storage Utilization

Storage utilization is a metric that we use to evaluate the performance of our Terminals segment. We define storage utilization as the percentage of the contracted capacity in barrels compared to the design capacity of the tank.

Segment Gross Margin and Gross Margin

Segment gross margin and gross margin are metrics that we use to evaluate our performance. We define segment gross margin in our Gathering and Processing segment as total revenue less unrealized gains or plus unrealized (losses) on commodity derivatives, construction and operating management agreement income and the cost of natural gas, crude oil and NGLs and condensate purchased.

We define segment gross margin in our Transmission segment as total revenue less the cost of natural gas purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

We define segment gross margin in our Terminals segment as total revenue less direct operating expense which includes direct labor, general materials and supplies and direct overhead.

Gross margin is a supplemental non-GAAP financial measure that we use to evaluate our performance. We define gross margin as the sum of the segment gross margins for our Gathering and Processing, Transmission and Terminals segments. The GAAP measure most directly comparable to gross margin is Net income (loss) attributable to the Partnership. For a reconciliation of gross margin to Net income (loss), please see "- Note About Non-GAAP Financial Measures" below.

Operating Margin

Operating margin is a supplemental non-GAAP financial measure that we use to evaluate our performance. We define operating margin as total gross margin less direct operating expenses. The GAAP measure most directly comparable to operating margin is net income (loss) attributable to the Partnership. For a reconciliation of Operating Margin to net income (loss), please see "- Note About Non-GAAP Financial Measures" below.

Direct Operating Expenses

Our management seeks to maximize the profitability of our operations in part by minimizing direct operating expenses without sacrificing safety or the environment. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities, lost and unaccounted for gas, and contract services comprise the most significant portion of our operating expenses. These expenses are relatively stable and largely independent of throughput volumes through our systems but may fluctuate depending on the activities performed during a specific period.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure used by our management and external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess: the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash flow to make cash distributions to our unitholders and our general partner; 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.

We define Adjusted EBITDA as net income (loss) attributable to the Partnership, plus interest expense, income tax expense, depreciation, amortization and accretion expense attributable to the Partnership, debt issuance costs paid during the period, distributions from investments in unconsolidated affiliates, transaction expenses primarily associated with our JPE Merger, Delta House acquisition, and Emerald transactions, certain non-cash charges such as non-cash equity compensation expense, unrealized (gains) losses on derivatives and selected charges that are unusual, less Construction and operating management agreement income, Other post-employment benefits plan net periodic benefit, earnings in unconsolidated affiliates, gains (losses) on the sale of assets, net, and selected gains that are unusual. The GAAP measure most directly comparable to our performance measure Adjusted EBITDA is net income (loss) attributable to the Partnership. For a reconciliation of Adjusted EBITDA to net income (loss), please see "- Note About Non-GAAP Financial Measures" below.

Note About Non-GAAP Financial Measures

Gross margin, operating margin and Adjusted EBITDA are non-GAAP financial measures. Each has important limitations as an analytical tool because it excludes some, but not all, items that affect the most directly comparable GAAP financial measures. Management compensates for the limitations of these non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

You should not consider gross margin, operating margin, or Adjusted EBITDA in isolation or as a substitute for, or more meaningful than analysis of, our results as reported under GAAP. Gross margin, operating margin and Adjusted EBITDA may be defined differently by other companies in our industry. Our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

The following tables reconcile the non-GAAP financial measures of gross margin, operating margin and Adjusted EBITDA used by management to Net income (loss) attributable to the Partnership, their most directly comparable GAAP measure, for the years ended December 31, 2016, 2015 and 2014, respectively (in thousands):

	Years Ended December 31,		
	2016 (1)	2015 (1)	2014 (1)
Reconciliation of Gross Margin to Net income (loss) attributable to the Partnership			
Gathering and processing segment gross margin (2)	$74,582	$76,865	$50,817
Transmission segment gross margin (2)	41,233	35,301	42,828
Terminals segment gross margin (2)	14,250	10,035	9,010
Gross margin	130,065	122,201	102,655
Less:			
Direct operating expenses (2)	53,265	53,017	39,425
Operating margin	76,800	69,184	63,230
Plus:			
Gain (loss) on commodity derivatives, net	(840)	1,324	1,091
Earnings in unconsolidated affiliates	40,158	8,201	348
Less:			
Corporate expenses	54,223	29,818	24,422
Depreciation, amortization and accretion expense	46,022	38,014	28,832
Loss on sale of assets, net	591	3,011	122
Loss on impairment of property, plant and equipment	697	—	99,892
Loss on impairment of goodwill	—	118,592	—
Interest expense	15,499	14,745	7,577
Other expense	—	—	670
Other, net (3)	(2,305)	770	(208)
Income tax expense	2,057	1,134	557
Income from discontinued operations, net of tax	—	80	611
Net income attributable to noncontrolling interest	2,804	25	214
Net income (loss) attributable to the Partnership	$(3,470)	$(127,480)	$(98,020)

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(1) During these years, we had the following transactions that affect comparability: i) in October 2016 and April 2016 we acquired a 6.2% and a 1% non-operated interest in Delta House Class A Units, respectively; ii) in April 2016, we acquired membership interests in Destin (49.7%), Tri-States (16.7%), Okeanos (66.7%), and Wilprise (25.3%), which we account for as an equity method investments; iii) in April 2016 we acquired a 60% interest in American Panther which we fully consolidate; iv) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House, which we account for as an equity method investment; and v) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which are included in our Gathering and Processing segment.

(2)

Direct operating expenses includes Gathering and Processing segment direct operating expenses of $41.3 million, $39.2 million, and $23.8 million, respectively, and Transmission segment direct operating expenses of $11.9 million, $13.8 million, and $15.6 million, respectively, for the year ended December 31, 2016, 2015 and 2014, respectively. Direct operating expenses related to our Terminals segment of $8.6 million, $7.7 million, and $6.5 million, respectively, are included within the calculation of Terminals segment gross margin for the year ended December 31, 2016, 2015 and 2014, respectively.

(3) Other, net includes realized gain (loss) on commodity derivatives of $(0.8) million, $1.6 million and $0.7 million and COMA income of $1.5 million, $0.8 million and $0.9 million, respectively, for each of the years ended December 31, 2016, 2015, respectively and 2014, respectively.

	Years Ended December 31,		
	2016	2015	2014
Reconciliation of Net income (loss) attributable to the Partnership to Adjusted EBITDA:			
Net income (loss) attributable to the Partnership	$(3,470)	$(127,480)	$(98,020)
Add:			
Depreciation, amortization and accretion expense	45,252	38,014	28,832
Interest expense	23,586	13,631	6,433
Debt issuance costs paid	11,140	2,238	3,841
Unrealized (gain) loss on derivatives, net	(10,221)	71	(595)
Non-cash equity compensation expense	2,818	3,863	1,626
Corporate office relocation	9,096	—	—
Transaction expenses [(1)]	9,071	1,426	1,794
Income tax expense	2,057	953	224
Impairment on property, plant and equipment	697	—	99,892
Loss on impairment of noncurrent assets held for sale	—	—	673
Loss on impairment of goodwill	—	118,592	—
Distributions from unconsolidated affiliates	83,046	20,568	1,980
General Partner contribution for cost reimbursement	—	330	—
Deduct:			
Earnings in unconsolidated affiliates	40,158	8,201	348
Construction and operating management agreement income	1,465	841	943
Other post-employment benefits plan net periodic benefit	17	14	45
Loss on sale of assets, net	(591)	(3,161)	(207)
Adjusted EBITDA	$132,023	$66,311	$45,551

(1) Transaction expenses for the year ended December 31, 2016 included JPE Merger costs of $7.2 million. The JPE Merger closed on March 8, 2017.

General Trends and Outlook

During 2017, our business objectives will continue to focus on maintaining stable cash flows from our existing assets and executing on growth opportunities to increase our long-term cash flows. We believe the key elements to stable cash flows are the diversity of our asset portfolio and our fee-based business which represents a significant portion of our estimated margins.

We anticipate maintenance capital expenditures between $8.0 million and $11.0 million, and approved expenditures for expansion capital between $45.0 million and$55.0 million, for the year ending December 31, 2017. Forecasted growth capital expenditures include East Texas Processing consolidation, expansion of the Harvey terminal, continued build-out of the Bakken system, and other organic growth projects.

We expect to continue to pursue a multi-faceted growth strategy, which includes maximizing drop down opportunities provided by our relationship with ArcLight, capitalizing on organic expansion and pursuing strategic third-party acquisitions in order to grow our cash flows. We expect the gradual increase in commodity prices that began in 2016 to continue throughout 2017 and as a result we expect producer and supplier activities to be impacted, which may increase the growth rate of our Gathering and Processing and Transmission segments.

We expect our business to continue to be affected by the key trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions prove to be incorrect, our actual results may vary materially from our expected results.

Gathering and Processing Segment. Except for our fee-based contracts, which may be impacted by throughput volumes, the profitability of our gathering and processing segment is dependent upon commodity prices, natural gas and crude oil supply, and demand for natural gas, crude oil, NGLs and condensate.

Transmission Segment. Profitability of our Transmission segment is dependent upon the demand to transport natural gas pursuant under our firm and interruptible transportation contracts. Throughput volumes could decline should natural gas prices and drilling levels decline.

Terminals Segment. Profitability of our terminals segment is dependent upon the demand from our customers to store their products, which is generally not tied to the crude oil and natural gas commodity markets. Currently, we have not experienced deterioration of terminal gross margin in connection with the volatility of the natural gas, crude oil, NGL or condensate markets. Further, the terms of our firm storage contracts are multiple years, with renewal options.

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $54.45 per barrel to a low of $26.21 per barrel from January 1, 2016 through March 13, 2017. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.80 per MMBtu to a low of $1.49 per MMBtu from January 1, 2016 through March 13, 2017. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices decline, this could lead to reduced profitability and may impact our liquidity, compliance with financial covenants in our Credit Agreement, and our ability to maintain our current distribution levels. Our long-term view is that as economic conditions improve, commodity prices should reach levels that will support continued natural gas and crude oil production in the United States. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

On January 26, 2017 the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit or $1.65 per common unit on an annualized basis. The distribution was paid on February 13, 2017, to unitholders of record as of the close of business on February 6, 2017. The amount of our cash distributions on our units principally depends upon the amount of cash we generate from our operations, which could be adversely impacted by market conditions and factors outside of our control. The Partnership Agreement allows us to reduce or eliminate quarterly distributions, if required to maintain ongoing operations.

Capital Markets. Volatility in the capital markets may impact our operations in multiple ways, including limiting our producers' ability to finance their drilling and workover programs and limiting our ability to fund drop downs, organic growth projects and acquisitions.

Impact of Inflation on Direct Operating Expenses. Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our operations fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high-energy commodity prices.

Results of Operations

Net loss attributable to the Partnership decreased by $124.0 million for the year ended December 31, 2016 as compared to 2015 primarily due to the loss on impairment of goodwill of $118.6 million recognized in 2015 and an increase in earnings from unconsolidated affiliates of $32.0 million from our investments in Delta House and the entities underlying the Emerald Transactions, offset by an increase in corporate expense of $24.4 million due to corporate relocation and JPE Merger expenses.

Gross margin increased by $7.9 million, or 6.4%, for the year ended to December 31, 2016 to $130.1 million as compared to the same period in 2015. The increase in gross margin was primarily due to an increase in our Transmission segment gross margin of $5.9 million as a result of increased revenues received by the Partnership due to the Pascagoula plant shutdown. The Pascagoula plant is not controlled or owned by the Partnership, and the shutdown required volumes to be directed to our High Point system. Gross margin also increased because of an increase in our Terminal segment gross margin of $4.3 million due to an increase in firm storage contracted capacity offset by a decrease in our Gathering and Processing segment gross margin of $2.3 million as a result of lower NGL and condensate production and lower realized prices.

For the year ended December 31, 2016, Adjusted EBITDA increased by $65.7 million, or 99.1% compared to 2015. The increase is primarily related to higher distributions from our unconsolidated affiliates of $62.5 million largely due to our investments in Delta House and the entities underlying the Emerald Transactions.

We distributed $53.5 million and $46.6 million to holders of our common units, or $1.71 and $1.89 per common unit, during the year ended December 31, 2016 and 2015, respectively.

The following table and discussion presents certain of our historical consolidated financial data for the periods indicated.

The results of operations by segment are discussed in further detail following this combined overview (in thousands):

	For the Years Ended December 31,		
	2016	2015	2014
Statements of Operations Data:			
Revenues:			
Sales of natural gas, NGLs and condensate	$160,950	$179,818	$255,025
Services	72,572	55,216	52,284
Gains (losses) on commodity derivatives, net	(840)	1,324	1,091
Total revenue	232,682	236,358	308,400
Operating expenses:			
Purchases of natural gas, NGLs and condensate	92,556	105,883	197,952
Direct operating expenses	61,861	60,737	45,919
Corporate expenses	54,223	29,818	24,422
Depreciation, amortization and accretion expense	46,022	38,014	28,832
Loss on sale of assets, net	591	3,011	122
Loss on impairment of property, plant and equipment	697	—	99,892
Loss on impairment of goodwill	—	118,592	—
Total operating expenses	255,950	356,055	397,139
Operating loss	(23,268)	(119,697)	(88,739)
Other income (expenses):			
Interest expense	(15,499)	(14,745)	(7,577)
Other expense	—	—	(670)
Earnings in unconsolidated affiliates	40,158	8,201	348
Income (loss) from continuing operations before income taxes	1,391	(126,241)	(96,638)
Income tax expense	(2,057)	(1,134)	(557)
Income (loss) from continuing operations	(666)	(127,375)	(97,195)
Loss from discontinued operations, net of tax	—	(80)	(611)
Net income (loss)	(666)	(127,455)	(97,806)
Net income attributable to noncontrolling interests	2,804	25	214
Net income (loss) attributable to the Partnership	$(3,470)	$(127,480)	$(98,020)
Other Financial Data (1):			
Gross margin	$130,065	$122,201	$102,655
Adjusted EBITDA	$132,023	$66,311	$45,551

(1)For definitions of gross margin and Adjusted EBITDA and reconciliations to their most directly comparable financial measure calculated and presented in accordance with GAAP, and a discussion of how we use gross margin and Adjusted EBITDA to evaluate our operating performance, please read the information in this Item under the caption “How We Evaluate Our Operations.”

Year ended December 31, 2016, compared to year ended December 31, 2015

Sales of natural gas, NGLs, and condensate revenue. Our sales of natural gas, NGLs, and condensate revenue for the year ended December 31, 2016 were $161.0 million compared to $179.8 million for the year ended December 31, 2015. This decrease of $18.8 million was primarily due to the following:

- a decrease in natural gas revenue of $10.7 million primarily due to lower realized natural gas prices of $2.51/Mcf, which is a decrease of $0.40/Mcf or 13.7% period over period;
- a decrease in NGL revenues of $6.3 million due to lower gross NGL production volumes of 38.2 Mgal/d from our Gathering and Processing segment and lower realized NGL prices of $0.57/gal, which is a decrease of $0.01/gal period over period; and
- a decrease in condensate revenues of $6.7 million due to lower realized condensate prices of $0.11/gal or 11.3% period over period, and lower condensate production of 13.2 Mgal/d from our Gathering and Processing segment;
- these decreases were partially offset by an increase in crude oil gathering fee-based revenues of $4.7 million.

Service revenue. Our service revenue for the year ended December 31, 2016 was $72.6 million compared to $55.2 million for the year ended December 31, 2015. This increase of $17.4 million was primarily due to the following:

- an increase in firm and interruptible transportation of $8.5 million primarily as a result of the Pascagoula plant shutdown and additional revenue associated with our Gulf of Mexico Pipeline which we acquired in April 2016. The Pascagoula plant is not controlled or owned by the Partnership, and the shutdown required volumes to be redirected to our High Point system;
- an increase in Terminals segment revenue of $5.0 million as a result of incremental storage utilization and ancillary increases; and
- an increase in management fees of $2.5 million from our acquired Gulf of Mexico Pipeline.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2016, were $92.6 million compared to $105.9 million in the year ended December 31, 2015. This decrease of $13.3 million was due to lower NGL and natural gas purchases of $6.1 million and $10.4 million, respectively, offset by an increase in crude oil purchases of $2.8 million related to our Bakken system which commenced operations in the fourth quarter of 2015. The decrease in NGL and natural gas purchases are the result of lower NGL and natural gas prices and lower NGL volumes related to our Gathering and Processing segment.

Gross Margin. Gross margin for the year ended December 31, 2016, was $130.1 million compared to $122.2 million for the year ended December 31, 2015. This increase of $7.9 million was primarily due to an increase in our Transmission segment gross margin of $5.9 million due to the Pascagoula plant shutdown, which increased the gross margin on our Highpoint system and a $4.3 million increase in our Terminals segment gross margin as a result of higher storage revenue. These increases were partially offset by a decrease in our Gathering and Processing segment gross margin of $2.3 million as a result of lower NGL and condensate production of 38.2 Mgal/d and 13.2 Mgal/d, respectively.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016, were $61.9 million compared to $60.7 million for the year ended December 31, 2015. This increase of 1.2 million was primarily due to an increase of contract services and labor costs.

Corporate expenses. Corporate expenses for the year ended December 31, 2016, were $54.2 million compared to $29.8 million for the year ended December 31, 2015. This increase of $24.4 million was primarily due to corporate relocation expenses of $9.1 million, JPE Merger expenses of $7.2 million, and increases in salaries, wages and benefits of $2.6 million due to increased employee expenses as we transitioned our corporate headquarters from Denver to Houston, information and technology maintenance costs of $1.1 million primarily related to systems and licenses that were implemented in the prior year, contract services of $1.0 million, and legal and regulatory compliance fees of $0.7 million in support of corporate activities.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the year ended December 31, 2016, was $46.0 million compared to $38.0 million for the year ended December 31, 2015. This increase of $8.0 million was primarily due to incremental depreciation of fixed assets related to our Gulf of Mexico Pipeline acquired in April 2016, our Mesquite joint venture and our Bakken system which began operations in October 2015.

Interest Expense. Interest expense for the year ended December 31, 2016, was $15.5 million compared to $14.7 million for the year ended December 31, 2015. This increase of $0.8 million was primarily due to higher outstanding borrowings under the Credit Agreement, an increase in our weighted average interest rate of 0.62% offset by $10.2 million of unrealized gains on our interest rate swaps.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2016 were $40.2 million compared to $8.2 million for the year ended December 31, 2015. This increase of $32.0 million was primarily due to incremental earnings of $22.8 million related to our investment in Delta House and $9.7 million related to the interests in the entities underlying the Emerald Transactions which were acquired in April 2016.

Year ended December 31, 2015, compared to year ended December 31, 2014

Sales of natural gas, NGLs, and condensate revenue. Our sale of natural gas, NGLs, and condensate revenue for the year ended December 31, 2015 was $179.8 million compared to $255.0 million for the year ended December 31, 2014. This decrease of $75.2 million was primarily due to the following:

- lower realized natural gas prices of $2.91/Mcf, which is a decrease of $2.01/Mcf, or 40.9%, period over period;
- lower realized condensate prices of $0.97/gal, which is a decrease of $0.65/gal, or 40.1%, period over period, offset by higher gross condensate production volumes of 24.6 Mgal/d, or 32.7%, period over period, from our Gathering and Processing segment; and
- converting fixed-margin contracts in our transmission segment to firm or interruptible transportation contracts;

These decreases were partially offset by:

- an increase in NGL revenues of $15.5 million as a result of higher gross NGL production volumes of 166.9 Mgal/d from our Gathering and Processing segment, which was offset by lower realized NGL prices of $0.58 gal, which is a decrease of $0.33/gal., period over period; and
- an increase in fee-based revenue of $19.0 million primarily due to increased average throughput volumes in our Gathering and Processing segment of 63.4 MMcf/day, or 23.1%.

Services revenue. Our service revenue for the year ended December 31, 2015 was $55.2 million compared to $52.3 million for the year ended December 31, 2014. This increase of $2.9 million was primarily due an increase in the Terminals segment revenue of $2.3 million as a result of increased storage utilization from acquiring new customers and contractual storage rate escalations.

Purchases of Natural Gas, NGLs and Condensate. Our purchases of natural gas, NGLs and condensate for the year ended December 31, 2015 were $105.9 million compared to $198.0 million in the year ended December 31, 2014. This decrease of $92.1 million was due to lower natural gas purchases of $94.3 million primarily as a result of lower natural gas prices and lower natural gas volumes related to our elective processing arrangements in our Gathering and Processing segment, as well as the conversion of certain fixed-margin contracts to interruptible transportation contracts in our Transmission segment as mentioned above.

This decrease was partially offset by incremental NGL, crude oil and condensate purchases of $2.2 million primarily associated with the gathering and processing systems acquired in the Costar Acquisition.

Gross Margin. Gross margin for the year ended December 31, 2015 was $122.2 million compared to $102.7 million for the year ended December 31, 2014. This increase of $19.5 million was primarily due to an increase in our Gathering and Processing segment gross margin of $26.0 million as a result of higher NGL and condensate production of 166.9 Mgal/d and 24.6 Mgal/d, respectively, and higher throughput volumes of 63.4 MMcf/d, as well as an increase in our Terminals segment gross margin of $1.0 million. These increases were partially offset by a decrease in our Transmission segment gross margin of $7.5 million as a result of a decrease in average throughput volumes.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015 were $60.7 million compared to $45.9 million in the year ended December 31, 2014. This increase of $14.8 million was primarily due to $13.4 million of incremental operating costs, including costs related to direct labor and benefits, associated with the gathering and processing systems acquired from Costar, and an increase of $2.1 million in operating costs associated with compression rentals used at our Lavaca System. These increases were partially offset by the timing of activities related to our integrity management and plant repair and maintenance programs.

Corporate expenses . Corporate expenses for the year ended December 31, 2015 were $29.8 million compared to $24.4 million for the year ended December 31, 2014. This increase of $5.4 million was primarily due to personnel costs incurred to manage and integrate our recent acquisitions and support continuing growth.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the year ended December 31, 2015 was $38.0 million compared to $28.8 million for the year ended December 31, 2014. This increase of $9.2 million was primarily due to incremental depreciation of fixed assets and amortization of certain intangible assets associated with the Costar Acquisition and the continuing capital expansion of the Lavaca System.

Loss on Impairment of Property, Plant and Equipment. During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil has led to a corresponding decrease in crude oil and natural gas production and is impacting the volume of natural and NGLs we gather and process on certain assets. As a result, asset impairment charges of $99.9 million related to certain gathering and processing assets were recorded during the fourth quarter of 2014.

Loss on Impairment of Goodwill. During the fourth quarter of 2015, management performed the Partnership's annual goodwill impairment test. As a result of the continuing decline in commodity prices, as well as the decline in the market price for the Partnership's common units during the fourth quarter, key assumptions relating to expected producer volumes and commodity prices used in management's impairment testing cash flow models were updated. The updated assumptions resulted in the estimated fair value of the Costar and Lavaca reporting units being less than their respective carrying values, indicating that the related goodwill was impaired. After completing an allocation of the estimated fair value of each reporting unit to the associated assets and liabilities, management determined that the goodwill of the Costar and Lavaca reporting units had a nominal fair value and that impairment charges of $118.6 million were required. Such impairment charges were recorded during the fourth quarter of 2015.

Interest Expense. Interest expense for the year ended December 31, 2015, was $14.7 million compared to $7.6 million for the year ended December 31, 2014. This increase of $7.1 million was primarily due to higher outstanding borrowings under the Credit Agreement to fund our capital growth projects and the Costar acquisition and Delta House Investment.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2015 was $8.2 million compared to $0.3 million for the year ended December 31, 2015. This increase of $7.9 million was due to incremental earnings of $7.5 million related to Delta House, and higher earnings from MPOG of $0.4 million.

Results of Operations — Segment Results

Gathering and Processing Segment

The table below contains key segment performance indicators related to our Gathering and Processing segment (in thousands except operating and pricing data).

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Gathering and Processing segment			
Financial data:			
Sales of natural gas, NGLs and condensate revenue	$153,174	$170,197	$202,035
Services revenue	10,531	3,400	1,581
Gain (loss) on commodity derivatives, net	(836)	1,324	1,091
Total revenue	$162,869	$174,921	$204,707
Purchases of natural gas, NGLs and condensate	87,026	97,580	152,690
Direct operating expenses	41,345	39,249	23,806
Other financial data:			
Segment gross margin	$74,582	$76,865	$50,817
Operating data:			
Average throughput (MMcf/d)	393.7	338.2	274.8
Average plant inlet volume (MMcf/d) (1)	102.1	120.9	89.1

Average gross NGL production (Mgal/d) (1)	192.9	231.1	64.2
Average gross condensate production (Mgal/d) (1)	86.6	99.8	75.2
Average realized prices:			
Natural gas ($/Mcf)	$2.51	$2.91	$4.92
NGLs ($/gal)	$0.57	$0.58	$0.91
Condensate ($/gal)	$0.86	$0.97	$1.62

(1) Excludes volumes and gross production under our elective processing arrangements.

Year Ended December 31, 2016, Compared to Year Ended December 31, 2015

Sales of natural gas, NGLs, and condensate revenue. Segment sales of natural gas, NGLs, and condensate revenue for the year ended December 31, 2016 were $153.2 million compared to $170.2 million for the year ended December 31, 2015. This decrease of $17.0 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 13.7%, 1.7%, and 11.3%, respectively; and
- lower average NGL and condensate production of 38.2 Mgal/d and 13.2 Mgal/d, respectively, primarily due to a decrease in volumes at our Longview system.

Service revenue. Segment service revenue for the year ended December 31, 2016 was $10.5 million compared to $3.4 million for the year ended December 31, 2015. This increase of $7.1 million was due to higher average throughput volumes of 55.5 MMcf/d and increased management fees due to our acquired Gulf of Mexico Pipeline.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2016 were $87.0 million compared to $97.6 million for the year ended December 31, 2015. This decrease of $10.6 million was due to lower realized commodity prices as well as lower NGL and condensate purchased volumes at the Longview system.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016 was $74.6 million compared to $76.9 million for the year ended December 31, 2015. This decrease of $2.3 million was primarily due to lower production on our Longview and Lavaca systems partially offset by increased gross margin from the Gulf of Mexico Pipeline.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $41.3 million compared to $39.2 million for the year ended December 31, 2015. This increase of $2.1 million was primarily due to operating expenses of $2.6 million incurred at the Gulf of Mexico Pipeline offset by lower compressor rentals due to ongoing cost cutting efforts.

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

Sales of natural gas, NGLs, and condensate revenue. Segment sales of natural gas, NGLs, and condensate revenue for the year ended December 31, 2015 were $170.2 million compared to $202.0 million for the year ended December 31, 2014. This decrease of $31.8 million was primarily due to lower realized natural gas, NGL and condensate prices of 40.9%, 36.3%, and 40.1%, respectively. These decreases were partially offset by higher average NGL and condensate production of 166.9 Mgal/d and 24.6 Mgal/d, respectively.

Service revenue. Segment services revenue for the year ended December 31, 2015 was $3.4 million compared to $1.6 million for the year ended December 31, 2014. This increase of $1.8 million was primarily due to higher average throughput volumes of 63.4 MMcf/d related to the Costar and Lavaca acquisitions which occurred in 2014.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2015, were $97.6 million compared to $152.7 million for the year ended December 31, 2014. This decrease of $55.1 million was primarily due to lower purchase costs associated with natural gas and NGLs due to lower realized natural gas and NGL prices and lower natural gas volumes associated with our elective processing arrangements. These decreases were partially offset by incremental purchases associated with off-spec NGL and condensate throughput volumes related to the Longview System.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015, was $76.9 million compared to $50.8 million for the year ended December 31, 2014. This increase of $26.1 million was primarily due to incremental gross margin of $24.2 million related to the Longview, Chapel Hill, Danville, Yellow Rose, and Bakken Systems and higher gross margin of $4.8 million at our Lavaca System. These increases were partially offset by lower NGL and condensate production associated with our elective processing arrangements.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015, were $39.2 million compared to $23.8 million for the year ended December 31, 2014. This increase of $15.4 million was primarily due to the incremental operating costs associated with the gathering and processing systems acquired in the Costar and Lavaca acquisitions, partially offset by the timing of activities related to our integrity management and plant repair and maintenance programs.

Transmission Segment

The table below contains key segment performance indicators related to our Transmission segment (in thousands except operating and pricing data).

	For the Years Ended December 31, 2016	2015	2014
Segment Financial and Operating Data:			
Transmission segment			
Financial data:			
Sales of natural gas, NGLs and condensate revenue	$7,775	$9,600	$52,881
Services revenue	39,196	34,082	35,308
Loss on commodity derivatives, net	(4)	—	—
Total revenue	$46,967	$43,682	$88,189
Purchases of natural gas, NGLs and condensate	5,530	8,303	45,262
Direct operating expenses	11,920	13,768	15,619
Other financial data:			
Segment gross margin	$41,233	$35,301	$42,828
Operating data:			
Average throughput (MMcf/d)	683.2	708.6	778.9
Average firm transportation - capacity reservation (MMcf/d)	688.1	653.7	577.9
Average interruptible transportation - throughput (MMcf/d)	354.0	410.3	468.9

Sales of natural gas, NGLs, and condensate revenue. Segment sales of natural gas, NGLs, and condensate revenue for the year ended December 31, 2016, were $7.8 million compared to $9.6 million for the year ended December 31, 2015. This decrease of $1.8 million in revenue was primarily due to lower average throughput volumes of 25.4 MMcf/d.

Service revenue. Segment services revenue for the year ended December 31, 2016 was $39.2 million compared to $34.1 million for the year ended December 31, 2015. This increase of $5.1 million in revenue was primarily due to the Pascagoula plant shutdown, which required volumes to be redirected to our High Point system. The Pascagoula plant is not controlled or owned by the Partnership.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2016, were $5.5 million compared to $8.3 million for the year ended December 31, 2015. This decrease of $2.8 million was primarily due to lower throughput volumes and a decline in realized natural gas prices of $0.40.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016, was $41.2 million compared to $35.3 million for the year ended December 31, 2015. This increase of $5.9 million was primarily due to increased revenues for our Highpoint system as a result of the shutdown of the Pascagoula plant and other factors discussed above.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016, were $11.9 million compared to $13.8 million for the year ended December 31, 2015. This decrease of $1.9 million was primarily related to lower employee costs.

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

Sales of natural gas, NGLs, and condensate revenue.Segment sales of natural gas, NGLs, and condensate revenue for the year ended December 31, 2015 was $9.6 million compared to $52.9 million for the year ended December 31, 2014. This decrease of $43.3 million in revenue was primarily due to converting certain fixed-margin arrangements to interruptible and firm transportation agreements during the first quarter of 2015, which substantially reduced the sales of natural gas throughput volumes and also the need for us to purchase such volumes.

Services revenue. Segment services revenue for the year ended December 31, 2015 was $34.1 million compared to $35.3 million for the year ended December 31, 2014. This decrease of $1.2 million in revenue was primarily due to lower average throughput volumes.

Purchases of Natural Gas, NGLs and Condensate. Purchases of natural gas, NGLs and condensate for the year ended December 31, 2015, were $8.3 million compared to $45.3 million for the year ended December 31, 2014. This decrease of $37.0 million was primarily due to converting certain fixed-margin arrangements to interruptible and firm transportation agreements, and therefore substantially reducing our need to purchase natural gas.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015, was $35.3 million compared to $42.8 million for the year ended December 31, 2014. This decrease of $7.5 million was primarily due to changes in pipeline imbalances and lower interruptible transportation margins due to lower average throughput volumes of 70.3 MMcf/d, or 9.0%.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015, were $13.8 million compared to $15.6 million for the year ended December 31, 2014. This decrease of $1.8 million was primarily related to an ongoing cost cutting effort to reduce operating expenses.

Terminals Segment

The table below contains key segment performance indicators related to our Terminals segment (in thousands except operating data).

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Terminals segment			
Financial data:			
Services revenue	$22,845	$17,734	$15,395
Sales of natural gas, NGLs and condensate revenue	1	21	109
Total revenue	$22,846	$17,755	$15,504
Direct operating expenses	8,596	7,720	6,494
Other financial data:			
Segment gross margin	$14,250	$10,035	$9,010
Operating data:			
Contracted Capacity (Bbls)	2,011,133	1,487,542	1,247,058
Design Capacity (Bbls)	2,173,717	1,688,950	1,363,817
Storage Utilization (1)	92.5 %	88.1 %	91.4 %

(1) Excludes storage utilization associated with our discontinued operations.

Services revenue. Segment services revenue for the year ended December 31, 2016, was $22.8 million compared to $17.7 million for the year ended December 31, 2015. The increase of $5.1 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at our Harvey terminal.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $8.6 million compared to $7.7 million for the year ended December 31, 2015. The increase of $0.9 million was primarily related to liability classified awards of $0.4 million and employee severance of $0.3 million.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016, was $14.3 million compared to $10.0 million for the year ended December 31, 2015. The increase of $4.3 million was primarily attributable to an increase in storage revenue that was partially offset by the liability classified awards and severance activity related costs.

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

Services revenue. Segment services revenue for the year ended December 31, 2015, was $17.7 million compared to $15.4 million for the year ended December 31, 2014. The increase of $2.3 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at the Harvey terminal.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2015, were $7.7 million compared to $6.5 million for the year ended December 31, 2014. The increase of $1.2 million is primarily attributable to additional direct labor associated with providing ancillary services.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015, was $10.0 million compared to $9.0 million for the year ended December 31, 2014. The increase of $1.0 million was primarily attributable to an increase in storage revenue while managing direct labor costs associated with providing ancillary services.

Liquidity and Capital Resources

Our business is capital intensive and requires significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities.

Our principal sources of liquidity include cash from operating activities, borrowings under our Credit Agreement (as defined herein), issuance of equity in the capital markets or through private transactions, and financial support from ArcLight, who controls our General Partner. In addition, we may continue to seek to raise capital through the issuance of secured and unsecured senior notes. Given our historical success in accessing various sources of liquidity, we believe that the sources of liquidity described above will be sufficient to meet our short-term working capital requirements, medium-term maintenance capital expenditure requirements, and quarterly cash distributions for at least the next twelve months. In the event these sources are not sufficient, we would pursue other sources of cash funding, including, but not limited to, additional forms of debt or equity financing. In addition, we would reduce non-essential capital expenditures, controllable direct operating expenses and corporate expenses, as necessary, and our Partnership Agreement allows us to reduce or eliminate quarterly distributions, if required to maintain ongoing operations.

Our liquidity for the year ended December 31, 2016 was impacted by the following:

- The issuance of 8,571,429 Series C Units along with warrants to purchase up to 800,000 common units at an exercise price of $7.25 per common unit with a combined value of approximately $120.0 million, proceeds of which were used to partially fund the purchase our membership interests in the entities underlying the Emerald Transactions.
- The issuance of 2,333,333 Series D Units with a value of $34.5 million, the proceeds of which were used to partially fund the purchase of additional Delta House Class A Units. We also agreed to grant the Series D unitholders a warrant to purchase up to 700,000 common units at an exercise price of $22.00 per common unit if the Series D Units are still outstanding at June 30, 2017.
- Credit Agreement borrowings of $351.1 million and repayments of $165.0 million.
- issuance of the 3.77% Senior Notes resulting in net proceeds of approximately $57.7 million.
- issuance of 8.50% Senior Notes resulting in net proceeds of approximately $291.3 million.

Changes in natural gas, crude oil, NGL and condensate prices and the terms of our contracts have a direct impact on our generation and use of cash from operations due to their impact on net income (loss), along with the resulting changes in working capital. During 2016, we mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

The counterparties to certain of our commodity swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds is determined on a counterparty by counterparty basis, and is impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative natural gas and crude oil forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. As of December 31, 2016, we have not been required to post collateral with our counterparties.

At-The-Market (“ATM”) Offering

On October 18, 2015, we filed a prospectus supplement related to the offer and sale from time to time of up to $100 million of our common units through an at-the-market offering program. For the year ended December 31, 2016, we sold 248,561 common units resulting in net proceeds of $2.9 million, after deducting offering costs of $0.3 million. The net proceeds were used to repay amounts outstanding under the Credit Agreement. As of December 31, 2016, approximately $96.8 million remained available for sale under the program.

Our Credit Agreement

Effective as of April 25, 2016, the Partnership entered into the Second Amendment to the Amended and Restated Credit Agreement, which provided for maximum borrowings up to $750.0 million, with the ability to further increase the borrowing capacity to $900.0 million subject to lender approval.

On September 30, 2016 and in connection with entering into the 3.77% Note Purchase Agreement, the Partnership entered into the Limited Waiver and Third Amendment to the Amended and Restated Credit Agreement, which among other things, (i) allowed Midla Holdings, for so long as the 3.77% Senior Notes are outstanding, to be excluded from guaranteeing the obligations under the Credit Agreement and being subject to certain covenants thereunder, (ii) released the lien granted under the Credit Agreement related to D-Day’s equity interests in Delta FPS, LLC and (iii) deemed the equity interests in Delta House FPS, LLC to be excluded property under the Amended and Restated Credit Agreement.

On November 18, 2016, the Partnership entered into the Fourth Amendment to the Amended and Restated Credit Agreement. The Fourth Amendment (i) modified certain investment covenants to reflect the recently completed incremental acquisition of additional interests in Delta House (ii) permitted JPE’s existing credit facility (the “JPE Credit Facility”) to remain in place during the time period between (a) the consummation of the JPE Merger and (b) the payoff of the JPE Credit Facility, (iii) permitted the joining of JPE and its subsidiaries as guarantors under the Amended and Restated Credit Agreement, and (iv) permitted the integration of JPE and its subsidiaries into the Partnership’s ownership structure

Effective as of the closing of the JPE Merger on March 8, 2017, the Partnership entered into the Second Amended and Restated Credit Agreement, which increased our borrowing capacity from $750.0 million to $900.0 million and provided for an accordion feature that will permit, subject to the customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion.

Our obligations under the Second Amended and Restated Credit Agreement are secured by a lien on substantially all of our assets. Advances made under the Second Amended and Restated Credit Agreement are guaranteed on a senior unsecured basis by certain of our subsidiaries (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the Second Amended and Restated Credit Agreement include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance of loans and any accrued and unpaid interest will be due and payable in full at maturity on September 5, 2019.

The Second Amended and Restated Credit Agreement contains certain financial covenants, including (i) a consolidated total leverage ratio that requires our consolidated total indebtedness not to exceed 5.00 times adjusted consolidated EBITDA (as defined in the Second Amended and Restated Credit Agreement) for the prior twelve month period, adjusted in accordance with the Second Amended and Restated Credit Agreement (except for the current and up to the subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant may be increased to 5.50 times adjusted consolidated EBITDA), (ii) a minimum interest coverage ratio that requires our adjusted consolidated EBITDA to exceed consolidated interest charges by at least 2.50 times for the prior twelve month period, and (iii) a consolidated secured leverage ratio that requires our consolidated secured indebtedness not to exceed 3.50 times adjusted consolidated EBITDA for the prior twelve month period. The financial covenants in the Second Amended and Restated Credit Agreement may limit the amount available to us for borrowing to less than $900.0 million. We can elect to have loans under the Second Amended and Restated Credit Agreement bear interest either at a Eurodollar-based rate plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (i) the Federal Funds Rate, plus 0.50%, (ii) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its “prime rate”, or (iii) the Eurodollar Rate plus 1.00%, plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee ranging between 0.375% to 0.50% per annum, depending on our total leverage ratio then in effect, on the undrawn portion of the revolving loan.

The Second Amended and Restated Credit Agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

At December 31, 2016 and 2015, letters of credit outstanding under the Credit Agreement were $7.4 million and $1.8 million, respectively.

As of December 31, 2016, our consolidated total leverage ratio was 4.07 and our interest coverage ratio was 7.43, which were both in compliance with the related requirements of our Credit Agreement. At December 31, 2016, we had approximately $711.3 million of borrowings and $7.4 million in letters of credit outstanding under the $750.0 million Amended and Restated Credit Agreement leaving $31.3 million of available borrowing capacity.

As of December 31, 2016, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the leverage and interest coverage ratios included in the Second Amended and Restated Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions, or drop down transactions, as well as the associated financing for such initiatives.

8.50% Senior Notes

On December 28, 2016, the Partnership and American Midstream Finance Corporation, our wholly owned subsidiary (together with the Partnership, the “Issuers”) completed the issuance and sale of the 8.50% Senior Notes. The 8.50% Senior Notes were issued at par and provided approximately $294.0 million in proceeds, after deducting initial purchasers' discount of $6.0 million. This amount was deposited into escrow pending completion of the JPE Merger and is included in Restricted cash on our consolidated balance sheet as of December 31, 2016. The Partnership also incurred $2.7 million of direct issuance costs resulting in net proceeds related to the 8.50% Senior Notes of $291.3 million.

Under the terms of the escrow agreement governing the disbursement of the net proceeds, upon the closing of the JPE Merger and the satisfaction of the other conditions contained therein, the restricted cash was released from escrow and was used to repay and terminate JPE Credit Facility and reduce borrowings under the Partnership’s Credit Agreement.

The 8.50% Senior Notes will mature on December 15, 2021 with interest payable in cash semi-annually in arrears on June 15 and December 15, commencing June 15, 2017.

At any time prior to December 15, 2018, the Issuers may on one or more occasions redeem up to 35% of the aggregate principal amount of 8.50% Senior Notes, at a redemption price of 108.50% of the principal amount, plus accrued and unpaid interest to the redemption date, in an amount not greater than the net cash proceeds of one or more equity offerings by the Partnership, provided that:

- at least 65% of the aggregate principal amount of the 8.50% Senior Notes remains outstanding immediately after such redemption (excluding 8.50% Senior Notes held by the Partnership and its subsidiaries); and

- the redemption occurs within 180 days of the closing of each such equity offering.

Prior to December 15, 2018, the Issuers may redeem all or part of the 8.50% Senior Notes, at a redemption price equal to the sum of:

- the principal amount thereof, plus
- the make whole premium (as defined in the Indenture) at the redemption date, plus
- accrued and unpaid interest, to the redemption date

On and after December 15, 2018, the Issuers may redeem all or a part of the 8.50% Senior Notes, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest to the applicable redemption date, if redeemed during the twelve-month period beginning on December 15 of the years indicated below:

Year	Percentage
2018	104.250%
2019	102.125%
2020 and thereafter	100.000%

The Indenture restricts the Partnership’s ability and the ability of certain of its subsidiaries to, among other things: (i) incur, assume or guarantee additional indebtedness, issue any disqualified stock or issue preferred units, (ii) create liens to secure indebtedness, (iii) pay distributions on equity securities, redeem or repurchase equity securities or redeem or repurchase subordinated securities, (iv) make investments, (v) restrict distributions, loans or other asset transfers from restricted subsidiaries, (vi) consolidate with or merge with or into, or sell substantially all of its properties to, another person, (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries, (viii) enter into transactions with affiliates, (ix) engage in certain business activities and (x) enter into sale and leaseback transactions. These covenants are subject to a number of important exceptions and qualifications. If at any time the 8.50% Senior Notes are rated investment grade by either Moody’s Investors Service, Inc. or Standard & Poor’s Ratings Services and no Default or Event of Default (as each are defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

3.77% Senior Notes

On September 30, 2016, Midla Financing, Midla, and MLGT entered into the 3.77% Senior Note Purchase Agreement with the Purchasers. Pursuant to the 3.77% Senior Note Purchase Agreement, Midla Financing sold $60.0 million in aggregate principal amount of 3.77% Senior Notes. Principal and interest on the 3.77% Senior Notes is payable in installments on the last business day of each quarter beginning June 30, 2017 with the remaining balance payable in full on June 30, 2031. The average quarterly principal payment is approximately $1.1 million. The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million after deducting related issuance costs of $2.3 million.

Net proceeds from the 3.77% Senior Notes are restricted and will be used to fund project costs incurred in connection with the construction of the Midla-Natchez Line, the retirement of Midla’s existing 1920’s pipeline, the move of our Baton Rouge operations to the MLGT system and the reconfiguration of the DeSiard compression system and all related ancillary facilities. These proceeds can also be used to pay costs incurred in connection with the issuance of the 3.77% Senior Notes, and for general corporate purposes of Midla Financing.

The Note Purchase Agreement includes customary representations and warranties, affirmative and negative covenants (including financial covenants), and events of default that are customary for a transaction of his type. Midla Financing must maintain a debt service reserve account containing six months of principal and interest payments, and Midla Financing and the Note Guarantors (including any entities that become guarantors under the terms of the 3.77% Senior Note Purchase Agreement) are restricted from making distributions until June 30, 2017, unless the debt service coverage ratio is not less than, and is not projected to be for the following 12 calendar months less than, 1.20:1.00, and unless certain other requirements are met.

In connection with the 3.77% Senior Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing’s obligations. Also, Midla Financing and the Note Guarantors granted a security interest in substantially all of their tangible and intangible assets, including the membership interests in each Note Guarantor held by Midla Financing, and Financing Holdings pledged the membership interests in Midla Financing to the Collateral Agent.

Working Capital

Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Our working capital deficit was $28.8 million at December 31, 2016 compared to $10.1 million at December 31, 2015 with the $18.7 million increase due primarily to capital expenditures in connection with the Midla-Natchez Line and convertible preferred unit distributions which were included in Accrued expenses and other current liabilities at December

31, 2016. The Partnership plans to utilize the increase in the Second Amended and Restated Credit Agreement of $150.0 million to cover any capital requirements.

Cash Flows

The following table reflects cash flows for the applicable periods (in thousands):

	For the Years Ended December 31,		
	2016	2015	2014
Net cash provided by (used in):			
Operating activities	$45,362	$40,937	$21,478
Investing activities	(551,441)	(171,692)	(471,870)
Financing activities	509,018	130,256	450,490

Year Ended December 31, 2016, Compared to Year Ended December 31, 2015

Operating Activities. Net cash provided by operating activities was $45.4 million for the year ended December 31, 2016, compared to $40.9 million for the year ended December 31, 2015. Net cash provided by operating activities for the year ended December 31, 2016, compared to December 31, 2015 increased by $4.5 million mainly driven by an increase in net income of $8.2 million, excluding the $118.6 million goodwill impairment charge recorded in 2015, offset by a decrease in the change in operating assets and liabilities of $2.0 million.

Investing Activities. Net cash used in investing activities was $551.4 million for the year ended December 31, 2016, compared to $171.7 million for the year ended December 31, 2015. Cash used in investing activities for the year ended December 31, 2016 increased by $379.7 million period over period primarily due to (i) the change in restricted cash of $325.0 million as a result of the issuance of our 8.50% Senior Notes and our 3.77% Senior Notes, (ii) an increase in the funds used to acquire investments in unconsolidated affiliates specifically for our interests in the Emerald Transactions and additional interests in Delta House Investment of $84.5 million, (iii) higher costs of acquisitions of $10.1 million period over period, and (iv) a $4.7 million decrease in cash proceeds received on the disposition of assets.

These increases in cash used in investing activities were partially offset by $30.5 million of higher cash distributions received from investments in unconsolidated affiliates as a return of capital and $13.9 million of lower capital expenditures as a result of a decrease in growth capital projects in process.

Financing Activities. Net cash provided by financing activities was $509.0 million for the year ended December 31, 2016, compared to net cash provided by financing activities of $130.3 million for the year ended December 31, 2015. Cash provided by financing activities for the year ended December 31, 2016 increased by $378.7 million period over period primarily due proceeds from the 8.50% Senior Notes of $294.0 million, proceeds from the 3.77% Senior Notes of $60.0 million, and higher net borrowings primarily on our Credit Facility of $34.0 million, partially offset by an increase in unitholder distributions of $10.7 million.

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

Operating Activities. Net cash provided by operating activities was $40.9 million for the year ended December 31, 2015, compared to $21.5 million for the year ended December 31, 2014. Net cash provided by operating activities for the year ended December 31, 2015, increased by $19.4 million period over period primarily due to increased gross margin of $19.5 million, an increase in the change in operating assets and liabilities of $16.1 million and an increase in earnings from unconsolidated affiliates of $7.9 million. These increases in operating cash flows were partially offset by increases in direct operating expenses and corporate expenses of $14.8 million and $5.4 million, respectively, and an increase in interest expense of $7.2 million due to a higher outstanding borrowings as a result of the Costar acquisition and Delta House Investment; as well as, funding our capital growth projects during the current year.

Investing Activities. Net cash used in investing activities was $171.7 million for the year ended December 31, 2015, compared to $471.9 million for the year ended December 31, 2014. Cash used in investing activities for the year ended December 31, 2015 decreased by $300.2 million period over period primarily due to no cost of acquisitions for 2015 and cash received from acquisitions of $7.4 million in 2015 as compared to cost of acquisitions of $362.3 million in 2014, primarily related to reimbursement for certain capital expenditures that we have incurred, or will incur, related to the Costar acquisition, return of restricted cash of $15.0 million, and higher cash disbursements received from unconsolidated affiliates in excess of cumulative earnings of $10.7 million

These increases were offset by higher capital expenditures of $40.0 million primarily related to the Lavaca and Bakken Systems, and higher acquisitions of unconsolidated affiliates of $53.7 million related to equity method investments primarily related to the Delta House Investment.

Financing Activities. Net cash provided by financing activities was $130.3 million for the year ended December 31, 2015, compared to $450.5 million for the year ended December 31, 2014. Cash provided by financing activities for the year ended December 31, 2014, decreased by $320.2 million period over period primarily due to lower proceeds from the issuance of common units to the public of $121.8 million, cash distributions in excess of carrying value received related to the Delta House Investment of $96.3 million, lower net borrowings period over period of $90.1 million the absence of proceeds received from the issuance of Series B Units in 2014, and an increase in unit holder distributions of $25.4 million. These decreases in cash flows provided by financing activities were partially offset by the issuance of Series A-2 units for gross proceeds of $45.0 million.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2016, our material off-balance sheet arrangements and transactions included operating lease arrangements and service contracts. Please see "Contractual Obligations" for more information. There are no other transactions, arrangements, or other relationships associated with our investments in unconsolidated affiliates or related parties that are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Capital Requirements

The energy business is capital intensive, requiring significant investment for the maintenance of existing assets and the acquisition and development of new systems and facilities. We categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets) made to maintain our operating income or operating capacity; or

- expansion capital expenditures, incurred for acquisitions of capital assets or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the year ended December 31, 2016, capital expenditures totaled $123.1 million including expansion capital expenditures of $116.3 million, maintenance capital expenditures of $3.1 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $3.7 million. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our Partnership Agreement. We anticipate maintenance capital expenditures related to the Partnership between $8.0 million and $11.0 million and expansion capital expenditures between $45.0 million and $55.0 million for the year ending December 31, 2017. Forecasted growth capital expenditures include East Texas processing consolidation, expansion of the Harvey terminal, continued build-out of the Bakken system and other organic growth projects.

We intend to make cash distributions to our unitholders, convertible preferred unitholders and our General Partner and expect that we will distribute most of the cash generated by our operations.

As a result, we expect to fund acquisitions and future capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, and additional debt and equity issuances. If these sources are not sufficient, we may pursue the divestiture of non-core assets or reduce discretionary spending.

Integrity Management

Certain operating assets require an ongoing integrity management program under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our total program addresses approximately 106 high consequence areas that require on-going testing pursuant to DOT regulations. Over the course of the seven-year cycle, we expect to incur up to $7.2 million in integrity management testing expenses.

Distributions

We intend to pay a quarterly distribution for the foreseeable future although we do not have a legal obligation to make distributions except as provided in our Partnership Agreement.

On January 26, 2017, we announced that the Board of Directors of our General Partner declared a quarterly cash a distribution of $0.4125 per common unit for the fourth quarter ended December 31, 2016, or $1.65 per common unit on an annualized basis. The cash distribution was paid on February 13, 2017, to unitholders of record as of the close of business on February 6 2017.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2016 (in thousands):

	Total	Credit Agreement	3.77% Senior Notes	8.50% Senior Notes	Asset Retirement Obligation	Other
Less Than 1 Year	$12,320	$—	$1,677	$—	$ 6,499	$4,144
1 - 3 Years	719,247	711,250	3,039	—	—	4,958
3 - 5 Years	310,702	—	6,729	300,000	—	3,973
More Than 5 Years	106,353	—	48,555	—	44,363	13,435
Total	$1,148,622	$ 711,250	$60,000	$300,000	$ 50,862	$26,510

Impact of Seasonality

Results of operations in our Transmission segment are directly affected by seasonality due to higher demand for natural gas during the winter months, primarily driven by our LDC customers. On our AlaTenn system, we offer some customers seasonally-adjusted firm transportation rates that require customers to reserve capacity at rates that are higher in the period from October to March compared to other times of the year. On our Midla system, we offer customers seasonally-adjusted firm transportation reservation volumes that allow customers to reserve more capacity during the period from October to March compared to other times of the year. The combination of seasonally-adjusted rates and reservation volumes, as well as higher volumes overall, result in higher revenue and segment gross margin in our Transmission segment during the period from October to March compared to other times of the year. We generally do not experience seasonality in our Gathering and Processing and Terminals segment.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by our management to be critical to an understanding of the financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Use of Estimates. The preparation of financial statements in accordance with GAAP requires management to make estimates and judgments that affect our reported financial positions and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, i) estimating unbilled revenue, operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing tangible and intangible assets for possible impairment, iv) estimating the useful lives of our assets, v) accounting for income taxes, and vi) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from our estimates.

Property, Plant and Equipment. In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment is depreciated using the straight-line method over the estimated useful lives of the assets. The costs of renewals and betterments which extend the useful life of property, plant and equipment are also capitalized. The costs of repairs, replacements and maintenance projects are expensed as incurred.

Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values which would impact future depreciation expense.

Impairment of Long-Lived Assets. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value. An asset or asset group is considered impaired when the estimated undiscounted cash flows are less than the carrying amount. In that event, an impairment loss is recognized to the extent that the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations.

Impairment of Goodwill. We evaluate goodwill for impairment annually in the fourth quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.

Investment in unconsolidated affiliates. We hold membership interests in entities that own and operate natural gas pipeline systems and NGL and crude oil pipelines in and around Louisiana, Alabama, Mississippi and the Gulf of Mexico. While we have significant influence over these entities, we do not control them and therefore, they are accounted for using the equity method and are reported in Investment in unconsolidated affiliates in the consolidated balance sheets. We evaluate the recoverability of these investments on a regular basis and recognize impairment write-downs if we determine a loss in value represents an other than temporary decline.

Environmental Remediation. We recognize a liability and expense associated with environmental remediation if the existence of a liability is probable and the amount can be reasonably estimated. If governmental regulations change, we could be required to incur remediation costs that may have a material impact on our profitability.

Asset Retirement Obligations. We recorded liabilities for future asset retirement obligations associated with our pipeline and gathering and processing systems. The recognition of an asset retirement obligations requires management to make numerous estimates and judgments including the type, cost and timing of the related remediation activities. Changes in those estimates and judgments may result in changes to both the recorded asset retirement obligation as well as the capitalized asset retirement cost in our consolidated balance sheets at period end as well as the amount of accretion and depreciation expense recognized in our consolidated statements of operations future periods.

Revenue Recognition. We recognize revenue from the sale of commodities (e.g., natural gas, crude oil, NGLs or condensate) as well as from the provision of gathering, processing, transportation or storage services when all of the following criteria are met: i) persuasive evidence of an exchange arrangement exists, ii) delivery has occurred or services have been rendered, iii) the price is fixed or determinable and iv) collectability is reasonably assured. We recognize revenue from the sale of commodities and the related cost of product sold on the gross basis for those transactions where we act as the principal and take title to commodities that are purchased for resale. Revenue from firm storage contracts is recognized ratably, which is typically monthly, over the term of the lease. Revenue from throughput fees and ancillary fees are recognized as services are provided to the customer.

Price Risk Management Activities. We have structured our hedging activities in order to minimize our commodity pricing and interest rate risks and to help maintain compliance with certain financial covenants in our credit agreement. These hedging activities rely upon forecasts of our expected operations and financial structure. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecasted transactions and the level of hedging activity executed.

From the inception of our hedging program, we used mark-to-market accounting for our commodity hedges and interest rate swaps. We record monthly realized gains and losses on hedge instruments based upon cash settlements information. The settlement

91

amounts vary due to the volatility in the commodity market prices throughout each month. We also record unrealized gains and losses for the net change in the mark-to-market valuation of the hedges.

Recent Accounting Pronouncements.

For information regarding new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements, please refer to Note 1 "Organization, Basis of Presentation and Summary of Significant Accounting Policies" in Part II, Item 8 of this Annual Report, which is incorporated herein by reference.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to certain market risks that are inherent in our financial instruments and arise from changes in commodity prices and interest rates. A discussion of our market risk exposure in financial instruments is presented below.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, crude oil, NGLs and condensate in our Gathering and Processing segment. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Natural gas, crude oil and NGL prices are impacted by changes in the supply and demand for these energy commodities, as well as market uncertainty. For a discussion of the volatility of natural gas, crude oil, and NGL prices, please refer to "Item 1A. Risk Factors." Adverse effects on our cash flow from reductions in natural gas, crude oil and NGL prices could adversely affect our operating cash flows and our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, optimization of our assets, and the use of derivative contracts. Our overall direct exposure to movements in natural gas prices is minimal as a result of natural hedges inherent in our current contract portfolio. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing.

To minimize the effect of commodity prices and maintain our cash flow and the economics of our development plans, we enter into commodity hedge contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, acquisition economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price downturns while allowing us to participate in some commodity price upside. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the Board of Directors of our General Partner. Historically, the commodity derivatives are in the form of swaps and collars.

We enter into commodity contracts with counterparties. We may be required to post collateral with our counterparties in connection with our derivative positions. As of December 31, 2016, we have not been required to post collateral with our counterparties. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place with our counterparties that permit us to offset our commodity derivative asset and liability positions.

During 2016, we entered into several commodity contracts with financial counterparties to hedge our 2016 exposure to commodity prices. Due to our overall low commodity exposure relative to fee-based and fixed-margin contract portfolio, management seeks to opportunistically enter into commodity contracts to hedge our equity natural gas, NGL and crude oil exposure. We have not entered into commodity contracts to hedge production in 2017 and beyond as of

December 31, 2016. As of December 31, 2016 and 2015, we had no commodity derivative contracts outstanding.

Interest Rate Risk

During the year ended December 31, 2016, we had exposure to changes in interest rates on our indebtedness associated with our Credit Agreement. To manage the impact of the interest rate risk associated with our Credit Agreement, we entered into interest rate swaps.

As of December 31, 2016, our outstanding interest rate swap contracts consisted of the following (in thousands):

Notional Amount	Term	Fair Value
$200,000	January 3, 2017 thru September 3, 2019	$1,912
$100,000	January 1, 2018 thru December 31, 2021	$3,090
$150,000	January 1, 2018 thru December 31, 2022	$5,219
		$10,221

As of December 31, 2015, we had no interest rate swap contracts outstanding. Although the credit markets have recently experienced historical lows in interest rates, interest rates have increased recently and may continue to increase in the near future. As the overall economy strengthens, it is possible that monetary policy will begin to tighten, resulting in higher interest rates. Future interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $3.2 million for the year ended December 31, 2016.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the reports of our independent registered public accounting firm, begin on F-1 of this Annual Report.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to the management of our General Partner, including our General Partner's principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision of the principal executive officer and principal financial officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act). Based on our evaluation, our principal executive officer and principal financial officer concluded that the Partnership's disclosure controls and procedures were not effective as of December 31, 2016 as a result of a material weakness as described below.

Despite the material weakness, our principal executive officer and principal financial officer have concluded that the financial statements included in this report fairly present in all material respects our financial condition, results of operations and cash flows for the periods presented.

93

Inherent Limitations of Internal Controls

Our management does not expect that our disclosure controls and procedures will prevent or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been prevented or detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Management monitors the Partnership's disclosure controls and procedures and make modifications, as necessary, with the intent that the disclosure controls and procedures will be adequately designed and operating effectively to prevent or detect material misstatements to its consolidated financial statements and to deter fraud.

Management's Annual Report on Internal Control over Financial Reporting

Management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)). The Partnership's internal control over financial reporting was designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2016, based on criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation of internal control over financial reporting as described above, management concluded that the Partnership did not maintain a sufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with its financial reporting requirements. Specifically, individuals within the Partnership's financial accounting and reporting functions did not have the appropriate level of expertise to ensure that complex, non-routine transactions of the Partnership were recorded appropriately. This control deficiency resulted in out-of-period adjustments recorded to the consolidated statement of operations in the fourth quarter of 2016 and a revision to the 2015 consolidated balance sheet and consolidated statement of cash flows.

Management concluded that this deficiency in internal control over financial reporting could result in material misstatements of the Partnership's annual or interim consolidated financial statements that would not be prevented or detected on a timely basis. Accordingly, management concluded that this control deficiency constitutes a material weakness.

Because of the above-described material weakness in internal control over financial reporting, management concluded that our internal control over financial reporting was not effective as of December 31, 2016.

PricewaterhouseCoopers LLP, our independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, also audited the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2016, as stated in their report included on page F-1 of this Annual Report.

Material Weakness Remediation

Management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weakness identified. Specifically, we are taking numerous steps that we believe will address the underlying causes of the material weakness, primarily through the hiring of additional accounting personnel with technical accounting and financial reporting experience, the enhancement of our training programs within our accounting department, and the enhancement of our internal review procedures during the financial statement preparation process.

Changes in internal control over financial reporting

There were no changes in internal control over financial reporting that occurred during the three months ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our principal executive officer and principal financial officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this Annual Report on Form 10-K as Exhibits 31.1 and 31.2. The certifications of our principal executive officer and principal financial officer pursuant to 18 U.S.C. 1350 are furnished with this Annual Report on Form 10-K as Exhibits 32.1 and 32.2.

Item 9B. Other Information
None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We do not have directors or officers, which is commonly the case with publicly traded partnerships. We are managed by the directors and executive officers of our General Partner, American Midstream GP, LLC. Our General Partner is not elected by our unitholders and will not be subject to re-election in the future. HPIP and Magnolia own all of the membership interests in our General Partner. Our General Partner has a board of directors (the "Board"), and our unitholders are not entitled to elect the directors or directly or indirectly participate in our management or operations. Our General Partner owes certain fiduciary duties to our unitholders. Our General Partner is liable, as General Partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our General Partner.

Our partnership agreement provides for the Board of Directors of our General Partner to designate a Conflicts Committee ("Conflicts Committee"), as delegated by the Board as circumstances warrant, to review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. If the Board submits a matter to the Conflicts Committee, which will consist solely of independent directors, for their review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the Board is fair and reasonable to us. The members of the Conflicts Committee may not be executive officers or employees of our General Partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us and not a breach by our General Partner of any duties it may owe us or our unitholders. In addition, the Board has an Audit Committee ("Audit Committee"), that complies with the NYSE requirements, a compensation committee ("Compensation Committee"), and a hedge committee that oversees risk management activities.

Even though most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a listed limited partnership like us to have a majority of independent directors on the Board.

Our General Partner has adopted a Code of Business Conduct and Ethics, or Code of Ethics, that applies to the directors, officers and employees of our General Partner. If our General Partner amends the Code of Ethics or grants a waiver, including an implicit waiver, for the Code of Ethics, we will disclose the information on our website. Our General Partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

All of the senior officers of our General Partner devote a sufficient portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our business; however, they also devote a portion of their time to overseeing the management, operations, corporate development and future acquisition initiatives of our General Partner, which has separate ongoing business operations.

The non-management members of our General Partner's board of directors meet in executive sessions without management participation at least quarterly. These directors do not constitute a committee of the Board and therefore do not take action at such sessions, although the participating directors may make recommendations for consideration by the full board. Executive sessions are chaired by Gerald A. Tywoniuk, the chairman of the Audit Committee according to the charter of the Audit Committee.

Interested parties may communicate directly with the independent directors by submitting a communication in an envelope marked "Confidential" addressed to the "Independent Members of the Board of Directors" in the care of the Secretary of our General Partner at: American Midstream GP, LLC, 2103 CityWest Boulevard, Building #4, Suite 800, Houston, Texas 77042.

We make available free of charge, within the "Investor Relations—Corporate Governance" section of our website at http://www.americanmidstream.com, and in print to any unitholder who so requests, the Code of Ethics and our Corporate Governance Guidelines. Unitholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Secretary, American Midstream GP, LLC, 2103 CityWest Boulevard, Building #4, Suite 800, Houston, Texas 77042. The information contained on, or connected to, our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

The independent directors on our Board are Donald R. Kendall Jr., Peter A. Fasullo and Gerald A. Tywoniuk. Each of our independent directors serves as a member of the Audit Committee, with Mr. Tywoniuk serving as chairman. Our General Partner is generally required to have at least three independent directors serving on its board at all times. The Board has determined that Mr. Tywoniuk is a financial expert as defined by the NYSE and the Exchange Act and therefore eligible to chair the Audit Committee.

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the Board and are subject to the terms of their employment agreements, if applicable. The following table shows information for the executive officers and directors of our General Partner as of March 20, 2017:

Name	Age	Position with American Midstream GP, LLC
Lynn L. Bourdon III	54	Chairman of the Board, President and Chief Executive Officer
Eric T. Kalamaras	43	Senior Vice President and Chief Financial Officer
Rene L. Casadaban	48	Senior Vice President and Chief Operating Officer
Louis J. Dorey	61	Senior Vice President - Business Development
Regina L. Gregory	46	Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary
Michael J. Croney	38	Vice President, Chief Accounting Officer and Corporate Controller
Edward E. Greene	54	Vice President - Gathering, Processing, and Terminals
Jon E. Hanna	51	Vice President - Crude Oil Gathering and Logistics
Ryan K. Rupe	41	Vice President - Natural Gas Services and Offshore Pipelines
Bill Webb	60	Vice President - NGL PPL Operations
Cory Willis	40	Vice President - PPE NGL Operations
Stephen W. Bergstrom	59	Director
John F. Erhard	42	Director
Donald R. Kendall Jr.	64	Director
Daniel R. Revers	55	Director
Peter A. Fasullo	63	Director
Joseph W. Sutton	68	Director
Lucius H. Taylor	43	Director
Gerald A. Tywoniuk	55	Director

Executive officers

Lynn L. Bourdon III was appointed Chairman, President and Chief Executive Officer in December 2015. Most recently, Mr. Bourdon served as President and Chief Executive Officer of Enable Midstream Partners, LP. Prior to Enable Midstream, he served as Group Senior Vice President of NGL & Natural Gas Marketing, Petrochemical, Refined Products & Marine at Enterprise Products Partners, LP. Mr. Bourdon joined Enterprise as Senior Vice President of NGL Supply & Marketing in 2003 and served in various senior management positions during his tenure. Prior to his employment at Enterprise Products, Mr. Bourdon served as Senior Vice President and Chief Commercial Officer for Orion Refining Corporation. He also held leadership positions at En*Vantage, PG&E Gas Transmission and Valero, and earlier served in various capacities at the Dow Chemical Company. Lynn received a Bachelor of Science degree in mechanical engineering from Texas Tech University and an MBA from the University of Houston.

Eric T. Kalamaras was appointed Senior Vice President and Chief Financial Officer in July 2016. Prior to his appointment with the General Partner of the Partnership, Mr. Kalamaras served as Executive Vice President and Chief Financial Officer of Azure Midstream Partners, LP and Azure Midstream Company, LLC (“Azure”) until his departure in November 2015. On January 30, 2017, Azure filed a voluntary petition under Chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. Prior to

Azure, Mr. Kalamaras served as Chief Financial Officer at Valerus Energy Holdings, Delphi Midstream Partners, and Atlas Pipeline Partners, LP. Prior to Atlas Pipeline Partners, he spent a combined 10 years at Wells Fargo and Bank of America Securities providing investment banking and debt capital markets services to clients in the energy and natural resource industries. Mr. Kalamaras started his career as a financial analyst at Ford Motor Company, and holds a Bachelor of Science in Business Administration from Central Michigan University and a Master of Business Administration from Wake Forest University.

Rene L. Casadaban, was appointed Senior Vice President and Chief Operating Officer in March 2017. Mr. Casadaban has 26 years of midstream project management and business development experience for onshore, offshore and deepwater pipeline systems. Mr. Casadaban is the former Chief Operating Officer for Summit Midstream Partners, LP ("Summit"). Prior to joining Summit, Mr. Casadaban worked for Enterprise Products Partners LP as the Director for Deepwater Business Development of floating production platforms and offshore pipelines. Mr. Casadaban has also served as an independent consultant to ExxonMobil Corporation and GulfTerra Energy Partners, LP for Gulf of Mexico and international pipeline projects. At Land and Marine Engineering Limited, Mr. Casadaban was responsible for managing domestic and international pipeline river crossings and beach approaches by horizontal directional drilling. Mr. Casadaban began his career as a Field Engineer for McDermott International Inc. He currently serves on the Board of Angel Reach and is a graduate of Auburn University with a Bachelor of Science in Building Construction.

Louis J. Dorey has served as Senior Vice President of Business Development since joining the General Partner of the Partnership, in January of 2014. Previously he served in various capacities at Continuum Energy Services from 2005 to 2014, including strategic planning, mergers and acquisitions, corporate business development, capital markets activities and as interim CFO. During his tenure, Continuum acquired or developed 500 miles of gathering systems, 75 MMcf/d of processing capacity, a rail terminal, a crude oil trucking company and raised two tranches of private equity. Prior to joining Continuum, Mr. Dorey was employed by Dynegy Inc. from 1997 to 2002 where he held positions including Executive Vice President of Strategy and Planning, President of Marketing and Origination, and Interim CFO. He participated in over $2 billion of acquisitions and development transactions, managed five regional wholesale marketing offices and retail marketing group, and worked on the integration of two major mergers. From 1991 to 1997, Mr. Dorey was employed by Destec Energy Inc. where he served as the Vice President of Mergers and Acquisitions, leading the development or acquisition of over $2 billion of power plant transactions and the sale of Destec Energy Inc. to Dynegy Inc. He earned a Bachelor of Business Administration from the University of Oklahoma and a Juris Doctorate from the University of Texas.

Regina L. Gregory has served as our Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary
of our General Partner since September 2016. Prior to her appointment with the General Partner, she was General Counsel, Vice President and Corporate Secretary of Traverse Midstream Partners, LP. Prior to Traverse, Ms. Gregory served as General Counsel, Vice President, Legal, Corporate Secretary and Compliance Officer at Access Midstream Partners, LP. Preceding Access, she spent a combined eleven years at Midstream Energy Services, LLC, Frontier Energy Services, LLC and other midstream companies providing in-house legal counsel. Ms. Gregory began her career as an associate at Fulbright & Jaworski LLP in the energy and environmental section, focused on litigation and resolution of energy-related issues, general commercial, and contract-related matters. She received a Juris Doctor with highest honors from the University of Oklahoma College of Law and a Bachelor of Science in Business and Marketing from the University of Colorado.

Michael J. Croney was appointed as Vice President, Chief Accounting Officer and Corporate Controller in August 2016. Mr. Croney previously served as the Vice President and Controller for FloWorks International LLC in Houston, Texas. Prior to FloWorks International, he served as controller of North America for AXIP Energy Services and held various management positions at the AES Corporation. Mr. Croney started his career with KPMG and holds a Bachelor of Commerce Honours, Accounting from Nelson Mandela Metropolitan University. Mr. Croney is a licensed Chartered Accountant in South Africa and licensed CPA in the State of Virginia.

Edward E. Greene became Vice President - Gathering, Processing, and Terminals as of the closing of the merger with JPE on March 8, 2017. Mr. Greene joined American Midstream in March, 2016 as Vice President, Onshore Gathering and Processing and NGL Liquids Marketing. Prior to joining American Midstream, he had led the NGL and Crude businesses of Enable Midstream Partners, L.P. Prior to Enable, he served in a number of commercial leadership roles for Enterprise Products, including Vice President of Refined Products and Vice President of Unregulated NGL Assets. Mr. Greene joined Enterprise after over 20 years with the Dow Chemical Company, where he served in various capacities in Commercial Management, R&D, and Sales and Marketing. He received a Bachelor of Science in Chemical Engineering from the Georgia Institute of Technology.

Jon E. Hanna became Vice President - Crude Oil Gathering and Logistics as of the closing of the merger with JPE on March 8, 2017. Prior to his appointment, he served as Executive Vice President-Crude Oil Pipelines and Storage of JPE from September 2015 to March 2017 and served as Executive Vice President-Commercial and Business Development from January 2014 to September 2015. Prior to joining JPE, Mr. Hanna was Vice President-Business Development of Enable Midstream Partners, L.P., a natural gas gathering, processing, transportation and storage partnership, from August 2011 to December 2013. Prior to Enable, Mr. Hanna served as Vice President-Market Development for ONEOK Partners, a natural gas gathering, processing, storage and transportation partnership, from July 2007 to August 2011 and as Vice President-Business Development for ONEOK Hydrocarbon L.P., an NGL processing, storage and transportation partnership, from July 2005 to July 2007. Mr. Hanna held various other positions with ONEOK NGL Marketing, L.P. and ONEOK Energy Marketing from September 2000 to July 2005. Prior to joining ONEOK, Mr. Hanna held positions with Texaco Inc. relating to its NGL and natural gas businesses from November 1989 to September 2000. Mr. Hanna earned a Bachelor of Science in Business Administration from Drake University.

Ryan K. Rupe became Vice President - Natural Gas Services and Offshore Pipelines as of the closing of the merger with JPE on March 8, 2017. Previously, Mr. Rupe served as our Vice President of Natural Gas Services and Offshore Pipelines and as our Vice President of Commercial Operations. Prior to his appointment as an officer of American Midstream, he was a partner and served as Director of Commercial Operations for High Point Energy, LLC. Mr. Rupe joined High Point Energy from CIMA Energy, where he was an owner and served as Director of Gas Control/Scheduling and Manager of Gulf Coast Trading. Mr. Rupe is a graduate of Texas A&M University and is a member of the Texas A&M Athletic Hall of Fame and Major League Baseball Players Alumni Association.

Bill Webb became Vice President - NGL PPL Operations as of the closing of the merger with JPE on March 8, 2017. Mr. Webb previously served as the Senior Vice President of NGL Operations for the general partner of JPE. Mr. Webb joined JPE in October 2011 as the Regional Vice President of Operations with Pinnacle Propane. From May 2003 to Oct, 2011, Mr. Webb managed sales and business development for retail and commercial operations in the Midwest and South East US as Division Vice President of Sales and Marketing of Inergy, LLC. Mr. Webb served in various leadership positions with AmeriGas and AmeriGas Cylinder Exchange (PPX) from July 2000 to May 2003, and managed operations, sales, and logistics as Vice President of Operations, Airgas Southwest, September 1997 to July 2000. Mr. Webb also founded MCS, Supply Inc., a gas and industrial products supplier, in March 1989 and served as its President of retail and commercial operations prior to its acquisition by Airgas Southwest in September 1997. From June 1985 to March 1989, Mr. Webb managed construction and development of terminal, station and underground storage installations as Vice President of Operations and Project Management R&W Inc. Mr. Webb served in the United States Army as a Specialist in CIDPERS with Army Central Intelligence Division prior to his undergraduate work in electrical engineering at the University of Oklahoma.

Cory Willis became Vice President - PPE NGL Operations as of the closing of the merger with JPE on March 8, 2017. Mr. Willis previously served as the Senior Vice President-Terminals and Distribution of the general partner of JPE from September 2015 to March 2017 and as Vice President-Natural Gas Liquids of the general partner of JPE from March 2015 to September 2015. Mr. Willis provided independent consulting services to clients engaged in the acquisition, development, and operation of energy assets from October 2013 to February 2015. From September 2012 to September 2013, Mr. Willis was the Vice President, Asset Management - West for Atlantic Power Corporation. Mr. Willis joined Atlantic Power as Director, Asset Management in March 2011 and was Atlantic Power’s Vice President and Chief Administrative Officer from June 2011 through September 2012, leading the company’s Human Resources, Information Technology, and Environmental Health & Safety functions. From 2003 through February 2011, Mr. Willis worked for Goldman Sachs & Co. and its Cogentrix Energy subsidiary in various positions, including as Vice President, Development & Asset Management. Mr. Willis holds a Bachelor’s Degree in Information and Operations Management from Texas A&M University.

Directors

Stephen W. Bergstrom was elected as a member of the Board in April 2013 and was elected President and Chief Executive Officer in May 2013 and served as President and Chief Executive Officer until retiring from those positions in December 2015. He remains a member of the Board. He was appointed to the Board in connection with his affiliation with ArcLight, which controls our General Partner, and due to his breadth of experience in the energy industry. Mr. Bergstrom acted as an exclusive consultant to ArcLight from 2002 to 2015, assisting ArcLight in connection with its energy investments. Prior to his consultancy with ArcLight, Mr. Bergstrom worked from 1986 to

2002 for Natural Gas Clearinghouse, which became Dynegy, Inc. Mr. Bergstrom acted in various capacities at Dynegy, ultimately acting as its President and Chief Operating Officer. Prior to his time at Dynegy, Mr. Bergstrom acted as a gas supply representative for Northern Natural Gas from 1981 to 1986. Mr. Bergstrom began his career at Transco from 1980-1981. Mr. Bergstrom earned a Bachelor of Science from Iowa State University in 1979. We believe that Mr. Bergstrom's breadth of experience in the energy industry provide him with the necessary skills to be a member of the Board.

John F. Erhard was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Erhard, a Partner at ArcLight, joined the firm in 2001 and has 15 years of energy finance and private equity experience. Prior to joining ArcLight, he was an Associate at Blue Chip Venture Company, a venture capital firm focused on the information technology sector. Mr. Erhard began his career at Schroders, where he focused on mergers and acquisitions. Mr. Erhard earned a Bachelor of Arts in Economics from Princeton University and a Juris Doctor from Harvard Law School. Mr. Erhard previously served on the Board of Directors of Patriot Coal. In addition, Mr. Erhard has experience in the MLP sector having served on the board of directors of Buckeye GP Holdings, the publicly traded General Partner of Buckeye Partners (NYSE:

BPL). We believe that Mr. Erhard's 14 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Donald R. Kendall, Jr. was elected a member of the Board in July 2013. Mr. Kendall serves as an independent director and as a member of the Audit Committee. Mr. Kendall is currently Managing Director and Chief Executive Officer of Kenmont Capital Partners, LP, an investment management firm based in Houston specializing in alternative investments and private equity. Previously, Mr. Kendall was a Portfolio Manager for Carlson Capital, L.P., President of Cogen Technologies Capital Company, L.P., Chairman and Chief Executive Officer of Palmetto Partners, Ltd., and a Managing Director in the project finance and leasing group at Credit Suisse First Boston. He also currently serves as a director and audit committee chairperson of SolarCity and Stream Energy and as a director of Tangent Energy Solutions. In addition, Mr. Kendall serves in various capacities at not-for-profit organizations, including The Jane Goodall Institute, The Houston Zoo Conservation Committee, and Earthwatch International. He also is on the Board of Overseers of the Amos Tuck School of Business Administration at Dartmouth College. Mr. Kendall received a B.A. degree from Hamilton College and an M.B.A. with high honors from The Amos Tuck School of Business Administration. He was a Tuck Scholar and a recipient of the W. M. Bollenbach, Jr. Fellowship. We believe that Mr. Kendall's investment experience and general business knowledge qualifies him to be a member of the Board. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

Daniel R. Revers was elected as a member of the board of directors in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Revers is Managing Partner of and a co-founder of ArcLight and has 25 years of energy finance and private equity experience. Mr. Revers manages the Boston office of ArcLight and is responsible for overall investment, asset management, strategic planning, and operations of ArcLight and its funds. Prior to forming ArcLight in 2000, Mr. Revers was a Managing Director in the Corporate Finance Group at John Hancock Financial Services ("John Hancock"), where he was responsible for the origination, execution, and management of a $6 billion portfolio consisting of debt, equity, and mezzanine investments in the energy industry. Prior to joining John Hancock in 1995, Mr. Revers held various financial positions at Wheelabrator Technologies, Inc., where he specialized in the development, acquisition, and financing of domestic and international power and energy projects. Mr. Revers serves in various capacities for a number of not-for-profit organizations, currently serving on the Board of Overseers at the Amos Tuck School of Business Administration, and the Board of Directors of The Citizen Schools. Mr. Revers earned a Bachelor of Arts in Economics from Lafayette College and a Master of Business Administration from the Amos Tuck School of Business Administration at Dartmouth College. We believe that Mr. Revers' 25 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Peter A. Fasullo was elected as a member of the Board in June 2016. Mr. Fasullo serves as an independent director and as a member of the Audit Committee. Mr. Fasullo has 40 years of experience in the midstream and refining industries and currently serves as a Principal of En*Vantage, Inc. Mr. Fasullo co-founded En*Vantage, Inc., in March 1999, an energy investment and strategic management consulting firm that provides advisory services to energy and financial companies, having advised more than 300 clients in the energy and financial industries. In March 2016, En*Vantage was cited by Morgan Stanley as a leading energy consultancy. Prior to forming En*Vantage, Mr. Fasullo was with Valero Energy in various executive management positions in Valero’s midstream and refining businesses from 1983 to 1997. Shortly thereafter, Mr. Fasullo was hired to lead MAPCO Inc.'s corporate and business development department and helped merge MAPCO into the Williams Companies in 1998. From 1976 to 1980, Mr. Fasullo was a process engineer with M.W. Kellogg and from 1980 to 1983, he was a market consultant with PACE Consultants and Engineers advising midstream and refining companies. Mr. Fasullo earned a Bachelor of Arts and a Master of Chemical Engineering degree from Rice University, and a MBA from the University of Houston.

Joseph W. Sutton was elected as a member of the Board in May 2013 and was appointed to the Board in connection with his affiliation with ArcLight. He is a founder of High Point Energy a precursor company to the Partnership.

Since 2000, Mr. Sutton has been the manager of Sutton Ventures Group, LLC, an energy investment firm that he founded, which has investments in many energy companies In 2007, he founded and has since led Consolidated Asset Management Services, or CAMS, which provides asset management, operations and maintenance, information technology, budgeting, contract management and development services to power plant ventures, oil and gas companies, renewable energy companies and other energy businesses. From 1992 to November 2000, Mr. Sutton worked for Enron Corporation, an energy company, where he most recently served as vice chairman and as chief executive officer of Enron International. We believe that Mr. Sutton's over 20 years of energy finance experience provide him with the necessary skills to be a member of the Board.

Lucius H. Taylor was elected as a member of the Board in April 2013 and was appointed to the Board in connection with his affiliation with ArcLight. Mr. Taylor joined ArcLight in 2007. He has 16 years of experience in energy and natural resource finance and engineering. Prior to joining ArcLight, Mr. Taylor was a Vice President in the Energy and Natural Resource Group at FBR Capital Markets where he focused on raising public and private capital for companies in the power and energy sectors. Mr. Taylor began his career as a geologist and project manager at CH2M HILL, Inc., a global engineering, construction, and operations firm. Mr. Taylor earned a Bachelor of Arts in Geology from Colorado College, a Master of Science in Hydrogeology from the University of Nevada, and a Master of Business Administration from the Wharton School at the University of Pennsylvania. We believe that Mr. Taylor's 16 years of energy finance and private equity experience provide him with the necessary skills to be a member of the Board.

Gerald A. Tywoniuk was elected as a member of the Board in May 2011. From May 2010 to the present, Mr. Tywoniuk has provided interim and project CFO services. He also currently serves as a director and audit committee chairperson on the board of the General Partner of Westmoreland Resource Partners, LP (NYSE:WMLP) and serves as a director and audit committee member on the board of the General Partner of Landmark Infrastructure Partners LP (NASDAQ:LMRK). From June 2008 through August 2013, Mr. Tywoniuk served Pacific Energy Resources Ltd. in various senior roles (Senior Vice President, Finance beginning June 2008, Chief Financial Officer beginning August 2008, acting Chief Executive Officer and CFO beginning September 2009, Plan Representative beginning December 2010). He held these positions as an employee until May 2010 and as a consultant on a part-time basis until August 2013. Pacific Energy Resources Ltd. was an oil and gas acquisition, exploitation and development company. Mr. Tywoniuk joined the company in June 2008 to help the management team work through the company's financially distressed situation. The board of the company elected to file for Chapter 11 protection in March 2009. In December 2009, the company completed the sale of its assets, and in August 2013 completed its liquidation. Prior to joining Pacific Energy Resources Ltd., Mr. Tywoniuk acted as an independent consultant in accounting and finance from March 2007 to June 2008. From December 2002 through November 2006, Mr. Tywoniuk was Senior Vice President and Chief Financial Officer of Pacific Energy Partners, LP. From November 2006 to March 2007, Mr. Tywoniuk assisted with the integration of Pacific Energy Partners, LP after it was acquired by Plains All American Pipeline, L.P. Mr. Tywoniuk holds a Bachelor of Commerce degree from The University of Alberta, Canada, and is a Canadian chartered accountant. Mr. Tywoniuk has 34 years of experience in accounting and finance, including 12 years as the Chief Financial Officer of three public companies and four years as Vice President/Controller of a fourth public company. Mr. Tywoniuk's extensive accounting, financial and executive management experience, and his prior experience with publicly traded partnerships, provide him with the necessary skills to be a member of the Board and a member and the chairman of the Audit Committee. With respect to the Audit Committee, he also qualifies as an "audit committee financial expert."

Family Relationships

There are no family relationships among any of the Partnership's directors and executive officers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our General Partner's board of directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10% unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they file with the SEC.

Based solely on our review of the copies of such forms received by us, or written representations from reporting persons, we believe that during the year ended December 31, 2016, all filing requirements applicable to our officers, directors, and greater than 10% beneficial owners were met in a timely manner, except as set forth below:

- Late filing of a Form 4 for Eric Kalamaras related to grant of phantom units on July 26, 2016;
- Late filing of a Form 4 for Energy Spectrum Securities Corporation related to the disposition of common units on February 16, 2016;
- Late filing of a Form 4 for Louis Dorey related to grant of phantom units on February 26, 2016;

- Late filing of a Form 4 for Matt Rowland related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Ryan Rupe related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Dan Campbell related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Bill Mathews related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Tom Brock related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Michael Suder related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Tim Balaski related to grant of phantom units on February 26, 2016;
- Late filing of a Form 4 for Tim Balaski related to grant of phantom units on July 1, 2016; and
- Late filing of a Form 4 for Ryan Rupe related to grant of phantom units on July 1, 2016.

Item 11. Executive Compensation

Our General Partner, under the direction of the Board is responsible for managing our operations and employs all of the employees that operate our business. The compensation payable to the officers of our General Partner is paid by our General Partner and such payments are reimbursed by us on a dollar-for-dollar basis.

The following is a discussion of the compensation policies and decisions of the Compensation Committee of the Board, with respect to the following individuals, who are executive officers of our General Partner and referred to as the "named executive officers" for the fiscal year ended December 31, 2016:

Name	Position with American Midstream GP, LLC
Lynn L. Bourdon III	Chairman of the Board, President, and Chief Executive Officer
Eric T. Kalamaras	Senior Vice President and Chief Financial Officer (appointed July 2016)
Daniel C. Campbell	Senior Vice President and Chief Financial Officer (until resignation July 2016)
Matthew W. Rowland	Senior Vice President and Chief Operating Officer (until resignation March 2017)
Regina L. Gregory	Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary
Ryan K. Rupe	Vice President - Natural Gas Services and Offshore Pipelines
Michael D. Suder	Former President and Chief Executive Officer of Blackwater Midstream Corporation
William B. Mathews	Former Vice President Legal Affairs, General Counsel and Secretary

Our compensation program is designed to recognize key managers are critical to our Partnership's profitability and growth. We utilize compensation to attract and retain management talent and to motivate key employees to focus consistently on growth and value creation. In addition, our compensation program aligns incentives for management and unitholders, focusing on long-term value creation rather than short-term gain. To do this, our compensation program for key managers is made up of the following main components: i) base salary, designed to compensate our executives for work performed during the fiscal year; ii) short-term incentive programs, designed to reward our executives for our yearly performance and for their individual performances during the fiscal year; and iii) equity-based awards, meant to align our executives interests with our long-term performance.

This section should be read together with the compensation tables that follow, which disclose the compensation awarded to, earned by, or paid to, the named executive officers with respect to the three years ended December 31, 2016.

Role of the Board, the Compensation Committee and Management

The Board has appointed the Compensation Committee to assist the Board in discharging its responsibilities relating to compensation matters, including matters relating to compensation programs for directors and executive officers of the General Partner. The Compensation Committee has overall responsibility for evaluating and approving our compensation plans, policies and programs, setting the compensation and benefits of executive officers, and granting awards under and administering our equity compensation plans. The Compensation Committee is charged with, among other things, establishing compensation practices and programs that are i) designed to attract, retain and motivate exceptional leaders, ii) structured to align compensation with our overall performance and growth in distributions to unitholders, iii) implemented to promote achievement of short-term and long-term business objectives consistent with our strategic plans, and iv) applied to reward performance.

As described in further detail below under "— Elements of the Compensation Programs," the compensation programs for our executive officers consist of base salaries, annual incentive bonuses and awards under the American Midstream GP, LLC, Long-Term Incentive Plan, which we refer to as our LTIP, currently in the form of equity-based phantom units, as well as other customary employment benefits such as a 401(k) plan, and health and welfare benefits. We expect that total compensation of our executive officers and the components of compensation and allocation among components of their annual compensation will be reviewed on at least an annual basis by the Compensation Committee.

During 2016, the Compensation Committee discussed executive compensation issues at several meetings, and the Compensation Committee expects to hold additional executive compensation-related meetings in 2017 and in future years. Topics discussed and to be discussed at these meetings included and will include, among other things, i) assessing the performance of the Chief Executive Officer, with respect to our results for the prior year, ii) reviewing and assessing the personal performance of the executive officers and other key managers for the preceding year and iii) determining the amount of the bonus pool to be paid to our executives and other key managers for a given year after taking into account the target bonus amounts established for those executives and other key managers at the outset of the year. In addition, at these meetings, and after taking into account the recommendations of our Chief Executive Officer only with respect to executive officers and key managers other than our Chief Executive Officer, base salary levels and target bonus amounts (representing the bonus that may be awarded expressed as a dollar amount or as a percentage of base salary for the year) for our executive officers will be established by the Compensation Committee. In addition, the Compensation Committee will make its decisions with respect to any awards under the LTIP and recommend awards to the Board. Our Chief Executive Officer will provide periodic recommendations to the Compensation Committee regarding the performance and compensation of the other named executive officers as well as the amounts allocated to the short-term incentive plan and LTIP compensation pools.

Compensation Objectives and Methodology

The principal objective of our executive compensation program is to attract and retain individuals of demonstrated competence, experience and leadership who share our business aspirations, values, ethics and culture. A further objective is to provide incentives to and reward our executive officers and other key employees for positive contributions to our business and operations, and to align their interests with our unitholders' interests.

In setting our compensation programs, we consider the following objectives:

- to create unitholder value through sustainable earnings and cash available for distribution;
- to provide a significant percentage of total compensation that is "at-risk" or variable;
- to encourage significant equity holdings to align the interests of executive officers and other key employees with those of unitholders;
- to provide competitive, performance-based compensation programs that allow us to attract and retain superior talent; and
- to develop a strong linkage between business performance, safety, environmental stewardship, cooperation and executive compensation.

Taking account of the foregoing objectives, we structure total compensation for our executives to provide a guaranteed amount of cash compensation in the form of base salaries, while also providing a meaningful amount of annual cash compensation that is at risk and dependent on our performance and individual performance of the executives, in the form of discretionary annual bonuses. We also seek to provide a portion of total compensation in the form of equity-based awards under our LTIP, in order to align the interests of executives and other key employees with those of our unitholders and for retention purposes.

Compensation decisions for individual executive officers are the result of the subjective analysis of a number of factors, including the individual executive officer's experience, skills or tenure with us and changes to the individual executive officer's position. In evaluating the contributions of executive officers and our performance, although no pre-determined numerical goals were established, a variety of financial measures have been generally considered, including non-GAAP financial measures used by management to assess our financial performance, such as Adjusted EBITDA and distributable cash flow. For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read "Management's Discussion and Analysis —How We Evaluate Our Operations". In addition, a variety of factors related to the individual performance of the executive officer were taken into consideration.

In making individual compensation decisions, the Compensation Committee historically has not relied on pre-determined performance goals or targets. Instead, determinations regarding compensation have resulted from the exercise of judgment based on all reasonably available information and, to that extent, were discretionary. The amount of each executive officer's current compensation will be considered as a base against which determinations are made as to whether increases are appropriate to retain the executive officer in light of competition or in order to provide continuing performance incentives. Subject to the provisions contained in the executive officer's employment agreement, if any, the Compensation Committee has discretion to adjust any of the components of compensation to achieve our goal of recruiting, promoting and retaining executive officers and key individuals with the skills necessary to execute our business strategy and develop, grow and manage our business.

The Compensation Committee has also utilized benchmarking compensation levels across a range of publicly traded Master Limited Partnerships operating in the midstream market to inform specific award levels for named executive officers and key managers. Going forward, we expect that the Compensation Committee will make compensation decisions taking into account trends occurring within our industry, including from a peer group of companies, which we expect will include, but not be limited to, the following similar publicly traded partnerships: Blueknight Energy Partners LP, Crestwood Midstream Partners LP, Genesis Energy LP, JP Energy Partners LP, Martin Midstream Partners LP, and Rose Rock Midstream, LP.

Elements of the Compensation Programs

Overall, the executive officer compensation programs are designed to be consistent with the philosophy and objectives set forth above. The principal elements of our executive officer compensation programs are summarized in the table below, followed by a more detailed discussion of each compensation element.

Element	Characteristics	Purpose
Base Salaries	Fixed annual cash compensation. Executive officers are eligible for periodic increases in base salaries. Increases may be based on performance or such other factors as the Compensation Committee may determine.	Keep our annual compensation competitive with the defined market for skills and experience necessary to execute our business strategy.
Annual Incentive Bonuses	Performance-related annual cash incentives earned based on our objectives and individual performance of the executive officers. Increases or adjustments may be made based on both company and individual performance or such factors as the Compensation Committee may determine.	Align performance to our objectives that drive our business and reward executive officers for achieving our yearly performance objectives and for their individual contributions to these objectives during the fiscal year.
Equity-Based Awards (Phantom-units and Distribution Equivalent Rights)	Performance-related, equity-based awards granted at the discretion of the Compensation Committee. Awards are based on our performance and we take into account competitive practices at peer companies. Grants typically consist of phantom units that vest ratably over four years and may be settled upon vesting with either a net cash payment or an issuance of Common Units, at the discretion of the Board. Distribution Equivalent Rights, or DERs, and options have been granted on a limited basis. Future awards, such as options and DERs may be granted at the discretion of the Compensation Committee and subject to the approval of the Board.	Align interests of executive officers with unitholders and motivate and reward executive officers to increase unitholder value over the long term. Ratable vesting over a four-year period is designed to facilitate retention of executive officers.
Retirement Plan	Qualified retirement plan benefits are available for our executive officers and all other regular full-time employees. At our formation, we adopted and are maintaining a tax-deferred or after-tax 401(k)	Provide our executive officers and other

	plan in which all eligible employees can elect to defer compensation for retirement up to IRS imposed limits. The 401(k) plan permits us to make annual discretionary matching contributions to the plan. For 2016, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 5% of the employee's eligible compensation.	employees with the opportunity to save for their future retirement.
Health and Welfare Benefits	Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for our executive officers and all other regular full-time employees.	Provide benefits to meet the health and wellness needs of our executive officers, other employees and their families.

104

Base Salaries

Base salaries for our executive officers will be determined annually by an assessment of our overall financial and operating performance, each executive officer's performance evaluation and changes in executive officer responsibilities. While many aspects of performance can be measured in financial terms, senior management will also be evaluated in areas of performance that are more subjective. These areas include development and execution of strategic plans, leading the development of management and other employees, innovation and improvement in our business activities and each executive officer's involvement in industry groups and in the communities that we serve.

We seek to compensate executive officers for their performance throughout the year with annual base salaries that are fair and competitive within our marketplace. We believe that executive officer base salaries should be competitive with salaries for executive officers in similar positions and with similar responsibilities in our marketplace and adjusted for financial and operating performance and each executive officer's performance evaluation, length of service with us and previous work experience. Individual salaries have historically been established by the Compensation Committee based on the general industry knowledge and experience of its members, in alignment with these considerations, to ensure the attraction, development and retention of superior talent. Going forward, we expect that salary decisions will continue to focus on the above considerations and will also take into account relevant market data, including the market data and peer group data.

We expect that base salaries will be reviewed annually to ensure continuing consistency with market levels and our level of financial performance during the previous year. Future adjustments to base salaries and salary ranges will reflect movement in the competitive market as well as individual performance. Annual base salary adjustments, if any, for the Chief Executive Officer will be determined by the Compensation Committee. Annual base salary adjustments, if any, for the other executive officers will be determined by the Compensation Committee, taking into account input from the Chief Executive Officer.

The Compensation Committee approved the following base salaries for 2016 for the named executive officers as provided in the table below.

Name	Base Salary at the end of 2016
Lynn L. Bourdon III	$500,000
Eric T. Kalamaras	285,000
Daniel C. Campbell (resigned July 2016)	285,000
Matthew W. Rowland	285,000
Regina L. Gregory	275,000
Ryan K. Rupe	250,000
Michael D. Suder (resigned November 2016)	300,000
William B. Mathews (resigned October 2016)	265,000

Annual Incentive Bonuses

As one way of accomplishing our compensation objectives, executive officers are rewarded for their contribution to our financial and operational success through the award of discretionary annual cash incentive bonuses. Annual cash incentive awards, if any, for the Chief Executive Officer are determined by the Compensation Committee. Annual cash incentive awards, if any, for the other executive officers are determined by the Compensation Committee taking into account input from the Chief Executive Officer.

We expect to review cash bonus awards for the named executive officers annually to determine award payments for the prior fiscal year, as well as to establish target bonus amounts for the current fiscal year. At the beginning of each year, the Compensation Committee meets with the Chief Executive Officer to discuss Partnership and individual goals for the year and what each executive is expected to contribute in order to help the Partnership achieve those goals. However, the amounts of the annual bonuses have been and are determined at the discretion of the Compensation

Committee with input from the Chief Executive Officer.

While target bonuses for our executive officers have been initially set at dollar amounts that are between 75% to 100% of their base salaries, the Compensation Committee has had broad discretion to retain, reduce or increase the award amounts when making its final bonus determinations. Bonuses (similar to other elements of the compensation provided to executive officers) historically have not been solely based on a prescribed formula or pre-determined goals, specified performance targets but rather have been determined on a discretionary basis and generally have been based on a subjective evaluation of individual, company-wide and industry performances. Target bonus amounts for 2016 for all of the executive officers are set forth in the table below.

The Board and the Compensation Committee believe that this approach to assessing performance results in a more comprehensive evaluation for compensation decisions. In 2017, the Compensation Committee recognized the following factors in making discretionary annual bonus recommendations and determinations:

- a subjective company performance evaluation based on company-wide financial performance including actual EBITDA versus budgeted EBITDA to assess company performance and adjusted as needed for new acquisitions and major capital expenditure programs in 2016;
- a subjective individual performance evaluation for executive officers and other factors deemed relevant; and
- the scope, level of expertise and experience required for the executive officer's position.

These factors were selected as the most appropriate measures upon which to base the annual incentive cash bonus decisions because our Compensation Committee believes that they help to align individual compensation with performance and contribution. With respect to its evaluation of company-wide financial performance, although no pre-determined numerical goals were established, the Compensation Committee generally reviewed our results with respect to Adjusted EBITDA as compared to operating budget and cash available for distribution in making annual bonus determinations.

Following its performance assessment, and based on our financial performance with respect to these criteria and the Compensation Committee's qualitative assessment of individual performance, the Compensation Committee determined to award the base salary and incentive bonus amounts, which may be paid in cash or Common Units, set forth in the table below to our named executive officers for performance in 2016.

Name	2016 Base Salary	2016 Target Bonus	2016 Bonus Earned
Lynn L. Bourdon III	$500,000	$500,000	$750,000
Eric T. Kalamaras	285,000	106,875	92,000
Daniel C. Campbell (resigned July 2016)	285,000	—	—
Matthew W. Rowland	285,000	213,750	213,750
Regina L. Gregory	275,000	103,125	120,000
Ryan K. Rupe	250,000	150,000	160,000
Michael D. Suder (resigned November 2016)	300,000	—	—
William B. Mathews (resigned October 2016)	265,000	—	—

For 2016, the Compensation Committee determined base annual incentive compensation award recommendations on additional company-wide criteria as well as industry criteria, recognizing the following factors as part of its determination of annual incentive bonuses (without assigning any particular weight to any factor):

- financial performance for the prior fiscal year, including Adjusted EBITDA and distributable cash flow;
- distribution performance for the prior fiscal year;
- unitholder total return for the prior fiscal year; and
- competitive compensation data of executive officers.

These factors were selected as the most appropriate measures upon which to base the annual cash incentive bonus decisions going forward because the Compensation Committee believes that they will most directly correlate to increases in long-term value for our unitholders.

Equity-Based Awards

Design. The LTIP was adopted in November 2009 in connection with our formation and was most recently amended and restated in 2016. In adopting the LTIP, the Board recognized that it needed a source of equity to attract new members to and retain members of the management team, as well as to provide an equity incentive to other key employees and non-employee directors. We believe the LTIP promotes a long-term focus on results and aligns

executive and unitholder interests.
The LTIP is designed to encourage responsible and profitable growth while taking into account non-routine factors that may be integral to our success. Long-term incentive compensation in the form of equity grants are used to provide incentives for performance that leads to enhanced unitholder value, encourage retention and closely align the executive officers' interests with unitholders' interests. Equity grants provide a vital link between the long-term results achieved for our unitholders and the rewards provided to executive officers and other key employees.

Phantom Units. A phantom unit is a notional unit granted under the LTIP that entitles the holder to receive an amount of cash equal to the fair market value of one Common Unit upon vesting of the phantom unit, unless the Board elects to pay such vested phantom unit with a common unit in lieu of cash. Unless an individual award agreement provides otherwise, the LTIP provides that unvested phantom units are forfeited at the time the holder terminates employment or Board membership, as applicable. The terms of the award agreements of our named executive officers provide that a termination due to death or long-term disability results in full acceleration of vesting. In general, phantom units awarded under our LTIP vest as to 25% of the award on each of the first four anniversaries of the date of grant.

Equity-Based Award Policies. The LTIP is administered by the Compensation Committee of the Board. The Compensation Committee, at its discretion, may elect to settle such vested phantom units with a number of units equivalent to the fair market value of a Common Unit at the date of vesting in lieu of cash.

Generally, grants issued under the LTIP vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment. Ownership in the awards is subject to forfeiture until the vesting date.

Unit Options. A unit option is a right to purchase a Common Unit at the fair market value per Common Unit on the date of grant. The Compensation Committee has utilized unit option grants in special circumstances associated with the new hire or promotion of a named executive officer, and each award has unique vesting terms.

Deferred Compensation. Tax-qualified retirement plans are a common way that companies assist employees in preparing for retirement. We provide our eligible executive officers and other employees with an opportunity to save for their retirement by participating in our 401(k) plan. The 401(k) plan allows our executive officers and other employees to defer compensation (up to IRS imposed limits) for retirement and permits us to make annual discretionary matching contributions to the plan. For 2016, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 5% of the employee's eligible compensation. Decisions regarding this element of compensation do not impact any other element of compensation.

Other Benefits. Each of the named executive officers is eligible to participate in our employee benefit plans which provide for medical, dental, vision, disability insurance and life insurance benefits, which are provided on the same terms as available generally to all salaried employees.

Recoupment Policy. We currently do not have a recoupment policy applicable to annual incentive bonuses or equity awards. The Compensation Committee expects to continue to evaluate the need to adopt such a policy in 2017, in light of current legislative policies as well as economic and market conditions.

Employment, Change in Control and Severance Arrangements. The Board and the Compensation Committee consider the maintenance of a sound management team to be essential to protecting and enhancing our best interests. To that end, we recognize that the uncertainty that may exist among management with respect to their "at-will" employment with our General Partner may result in the departure or distraction of management personnel to our detriment. Accordingly, our General Partner has agreed to severance arrangements for Messrs. Bourdon and Kalamaras and Ms. Gregory that we believed were appropriate to encourage the continued attention and dedication of members of our management. These severance arrangements are described more fully below under "— Employment Agreements with Named Executive Officers."

Summary Compensation Table for the Three Years ended December 31, 2016

The following table sets forth certain information with respect to the compensation paid to the named executive officers for the three years ended December 31, 2016.

	Year	Salary	Bonus	Unit Awards [1]	All Other Compensation	Total Compensation
Lynn L. Bourdon III [2]	2016	$500,000	$750,000	$598,812	$ 15,838	$ 1,864,650
Chairman of the Board, President and Chief Executive Officer	2015	32,692	—	1,501,952	—	1,534,644
Eric T. Kalamaras [3] [9]	2016	137,019	92,000	359,730	240,189	828,938
Senior Vice President and Chief Financial Officer						
Daniel C. Campbell [4] [9]	2016	209,019	—	34,622	666,768	910,409
Senior Vice President and Chief Financial Officer	2015	295,962	28,000	515,658	—	839,620
	2014	285,000	250,000	300,982	10,413	846,395
Matthew W. Rowland [5]	2016	285,000	213,750	34,622	13,702	547,074
Senior Vice President and Chief Operating Officer	2015	295,962	28,000	349,328	1,644	674,934
	2014	285,000	250,000	300,982	—	835,982
Regina L. Gregory [6] [10]	2016	89,375	120,000	515,344	86,904	811,623
Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary						
Ryan K. Rupe	2016	250,000	160,000	243,727	—	653,727
Vice President Commercial Operations						
Michael D. Suder [7] [11]	2016	279,665	461,500	24,296	34,615	800,076
President and Chief Executive Officer of Blackwater Midstream	2015	311,538	28,000	371,600	—	711,138
	2014	304,423	40,625	256,163	—	601,211
William B. Mathews [8]	2016	235,952	—	21,461	370,962	628,375
Vice President Legal Affairs, General Counsel and Secretary	2015	272,115	120,000	324,816	13,096	730,027
	2014	245,000	150,000	202,020	8,952	605,972

(1) Amounts shown in this column do not reflect dollar amounts actually received by each of our named executive officers. Instead, these amounts reflect the aggregate grant date value of each phantom unit award or unit options award granted in each of the three years ended December 31, 2016. In general, employees are not entitled to distributions declared on the underlying unit while the phantom unit is unvested; therefore, the grant date fair value of the phantom units is calculated by reducing the grant date price, by the present value of the distributions expected to be paid on the underlying units during the requisite service period. For additional information on the assumptions used to calculate the grant date fair value of equity incentive awards, refer to Note 16 "Long-Term Incentive Plan" of this Annual Report, incorporated herein by reference.

2016 Unit Awards

	Grant date value of phantom units before distributions	Present value of distributions	Grant date value of phantom units less distributions
Lynn L. Bourdon III	$1,344,193	$745,381	$598,812
Eric T. Kalamaras *	$480,000	$195,600	$284,400
Daniel C. Campbell	$383,099	$348,477	$34,622
Matthew W. Rowland	$383,099	$348,477	$34,622
Regina L. Gregory *	$681,750	$289,800	$391,950
Ryan K. Rupe	$542,759	$299,032	$243,727
Michael D. Suder	$268,839	$244,543	$24,296
William B. Mathews	$237,474	$216,013	$21,461

* Does not include unit options awarded.

(2) Other compensation includes $12,438 of matching contributions that we make on account of employee contributions under our 401(k) Savings Plan and $3,400 of insurance premiums.

(3) Other compensation includes $236,078 of relocation expenses and $4,111 of matching contributions that we make on account of employee contributions under our 401(k) Savings Plan.

(4) Other compensation includes $657,451 of severance payments and $9,317 of matching contributions that we make on account of employee contributions under our 401(k) Savings Plan.

(5) Other compensation includes $13,702 of matching contributions that we make on account of employee contributions under our 401(k) Savings Plan.

(6) Other compensation includes $82,895 of relocation expenses and $4,009 of matching contributions that we make on account of employee contributions under our 401(k) Savings Plan.

(7) Other compensation represents severance payments.

(8) Other compensation includes $359,847 of severance payments and $11,115 of matching contributions that we make on account of employee contributions under our 401(k) Savings Plan.

(9)

Mr. Campbell resigned and Mr. Kalamaras was appointed to serve as Senior Vice President and Chief Financial Officer in July 2016.

(10) Ms. Gregory was appointed Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary in September 2016.

(11) Mr. Suder resigned as President and Chief Executive Officer of Blackwater Midstream in November 2016.

Grants of Plan-Based Awards for 2016

Name	Number of Securities Underlying Award	Type of Award	Exercise Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit Awards ($) (1)
Lynn L. Bourdon III				
02/26/2016 Grant	66,021	Phantom Units		$329,445
02/26/2016 Grant	198,064	Phantom Units		269,367
Eric T. Kalamaras				
07/26/2016 Grant	40,000	Phantom Units		284,400
08/26/2016 Grant (2)	30,000	Options	$ 12.00	75,330
Daniel C. Campbell				
02/26/2016 Grant	75,265	Phantom Units		34,622
Matthew W. Rowland				
02/26/2016 Grant	75,265	Phantom Units		34,622
Regina L. Gregory				
09/08/2016 Grant	45,000	Phantom Units		391,950
09/19/2016 Grant (3)	45,000	Options	$ 13.88	123,394
Ryan K. Rupe				
02/26/2016 Grant	35,493	Phantom Units		16,327
07/01/2016 Grant	30,000	Phantom Units		227,400
Michael D. Suder				
02/26/2016 Grant (4)	52,817	Phantom Units		24,296
William B. Mathews				
02/26/2016 Grant (5)	46,655	Phantom Units		21,461

(1) Amounts shown in this column do not reflect dollar amounts actually received by our named executive officers. Instead, these amounts reflect the aggregate grant date value. For additional information on the assumptions used to calculate the grant date fair value of equity incentive awards, refer to Note 16 "Long-Term Incentive Plan" of this Annual Report, which is incorporated herein by reference.

(2) The options will vest on July 31, 2019, subject to continued employment, and will expire on July 31st of the calendar year following the calendar year in which it vests.

(3) The options will vest at a rate of 25% per year. The options will expire on September 30th of the calendar year following the calendar year in which it vests.

(4) All unvested grants of phantom units were forfeited upon resignation from office.

(5) Half of the unvested grants of phantom units were forfeited upon resignation from office.

Employment Agreements with Named Executive Officers

Our General Partner has entered into an employment agreement with Lynn L. Bourdon III. The employment agreement with Mr. Bourdon has an initial term of three years, which will be automatically extended for successive one-year terms until either party elects to terminate the agreement by providing written notice at least 60 days prior to the end of the expiration of the initial or extended term, as applicable. The base salary and target bonus amounts set forth in Mr. Bourdon’s employment agreement is shown in the table below and the employment agreement provides that the base salary may be increased but not decreased. Mr. Bourdon’s employment agreement provides that he will be provided with the opportunity to earn an annual cash bonus, a certain percentage of which will be conditioned and determined on the attainment of personal performance goals and the balance of which will be conditioned and determined on the attainment of organizational performance goals, in each case as set by, and

110

based on performance criteria established by, the Compensation Committee. Mr. Bourdon's employment agreement also provides that the executive may also be eligible to receive awards under the LTIP as determined by the Compensation Committee.

Mr. Bourdon's employment agreement also contains certain confidentiality covenants prohibiting him from, among other things, disclosing confidential information relating to our General Partner or any of its affiliates, including us. The employment agreement also contains non-competition and non-solicitation restrictions, which apply during the term of Mr. Bourdon's employment with our General Partner and, with certain exceptions, continue for a period of 6-12 months following termination for any reason. Mr. Campbell was party to an employment agreement with the General Partner that terminated on July 11, 2016 and Mr. Rowland was party to an employment agreement with the General Partner that expired according to its terms on July 31, 2016. Both of the employment agreements for Mr. Campbell and Mr. Rowland contain certain non-competition and non-solicitation restrictions that have survived termination.

Mr. Bourdon's employment agreement also provides for, among other things, the payment of severance benefits under certain circumstances. The General Partner has also agreed to pay certain severance benefits under certain circumstances to Mr. Kalamaras and Ms. Gregory. Please refer to "- Potential Payment Upon Termination or Change in Control - Employment Agreements and Severance Agreements with Named Executive Officers" below for a description of these benefits under these agreements.

Outstanding Equity-Based Awards at December 31, 2016

The following table provides information regarding outstanding equity-based awards held by the named executive officers as of December 31, 2016. All such equity-based awards consist of phantom units and unit options granted under the LTIP.

Name	Unit Awards Number of Unvested Phantom Awards	Market Value (1)	Number of Unexercised Option Award	Option Exercise Price
Lynn L. Bourdon III (2)	398,064	$ 7,244,765	200,000	$ 7.50
Eric T. Kalamaras (3)	40,000	728,000	30,000	$ 12.00
Daniel C. Campbell	—	—	—	—
Matthew W. Rowland	93,567	1,702,919	—	—
Regina L. Gregory (4)	45,000	819,000	45,000	$ 13.88
Ryan K. Rupe	77,434	1,409,299	—	—
Michael D. Suder	—	—	—	—
William B. Mathews	—	—	—	—

(1) The market value of phantom units that had not vested as of December 31, 2016 was calculated based on the fair market value of our Common Units as of December 31, 2016 which was $18.20 multiplied by the number of unvested phantom units. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates Equity-Based Awards" in the 2016 Annual Report.

(2) In conjunction with the execution of Mr. Bourdon's employment agreement effective December 10, 2015, the Board approved an option grant to purchase 200,000 Common Units of the Partnership.The phantom units contain DERs based on the extent to which the Partnership's Series A Preferred Unitholders receive distributions in cash. The grant will vest on January 1, 2019, subject to acceleration in certain circumstances and will expire on March 15th of the calendar year following the calendar year in which it vests.

(3) Effective August 2016, the Board approved the grant of an option to purchase 30,000 common units. The grant will vest on July 31, 2019, subject to continued employment, and will expire on July 31st of the calendar year following

the calendar year in which it vests.

(4) Effective September 2016, the Board approved the grant of an option to purchase 45,000 common units. The options will vest at a rate of 25% per year, subject to continued employment. The options will expire on September 30th of the calendar year following the calendar year in which it vests.

Units Vested in 2016

The following table shows the phantom unit awards that vested during 2016.

Name	2016 Number of Units Acquired on Vesting	Fair Market Value per Unit Upon Vesting	Value Realized on Vesting (1)
Lynn L. Bourdon III			
02/26/2016 vest	66,021	$ 4.99	$ 329,445
Eric T. Kalamaras	—	—	—
Daniel C. Campbell			
02/19/2016 vest	3,712	6.61	24,536
02/23/2016 vest	4,533	6.19	28,059
09/02/2016 vest	21,021	13.62	286,306
Matthew W. Rowland			
02/19/2016 vest	3,712	6.61	24,536
02/23/2016 vest	3,626	6.19	22,445
08/22/2016 vest	8,334	12.12	101,008
Regina L. Gregory	—	—	—
Ryan K. Rupe			
02/19/2016 vest	2,123	6.61	14,033
02/23/2016 vest	2,565	6.19	15,877
Michael D. Suder			
02/19/2016 vest	3,160	6.61	20,888
02/23/2016 vest	3,817	6.19	23,627
William Mathews			
02/19/2016 vest	2,491	6.61	16,466
02/23/2016 vest	3,372	6.19	20,873

(1) The value realized upon vesting of phantom units is calculated based on the fair market value of our common units on the applicable vesting date.

Long-Term Incentive Plan

The Board has adopted a LTIP for employees, consultants and directors of our General Partner and affiliates who perform services for us. The plan provides for the issuance of options, unit appreciation rights, restricted units, phantom units, other unit-based awards, unit awards or replacement awards, as well as tandem DERs granted with respect to an award. To date, phantom units, phantom units with DERs, and options have been issued under the LTIP.

As of December 31, 2016, 1,245,843 unvested phantom units were outstanding under our LTIP and 275,000 unit options. A phantom unit is a notional unit granted under the LTIP that entitles the holder to receive an amount of cash equal to the fair market value of one common unit upon vesting of the phantom unit, unless the Board elects to settle such vested phantom unit with a common unit in lieu of cash. DERs may be granted in tandem with phantom units. Except as otherwise provided in an award agreement, DERs that are not subject to a restricted period are currently paid to the participant at the time a distribution is made to the unitholders, and DERs that are subject to a restricted period are paid to the participant in a single lump sum no later than the 15th day of the third calendar month following the date on which the restricted period ends. A unit option is a right to purchase our Common Units at a price equal to the fair market value of a Common Unit on the grant date.

The number of units that may be delivered with respect to awards under the LTIP may not exceed 7,175,352 units, subject to specified anti-dilution adjustments. However, if any award is terminated, canceled, forfeited or expires for any reason without the actual delivery of units covered by such award or units are withheld from an award to satisfy the exercise price or the employer's tax withholding obligation with respect to such award, such units will again be available for issuance pursuant to other awards granted under the LTIP. In addition, any units allocated to an award will, to the extent such award is paid in cash, be again available for delivery under the LTIP with respect to other awards. There is no limitation on the number of awards that may be granted under the LTIP and paid in cash. The LTIP provides that it is to be administered by the Board, provided that the Board may delegate authority to administer the LTIP to a committee of non-employee directors. As of March 9, 2017, there were 5,073,617 units available for future grant awards.

The LTIP may be terminated or amended at any time, including increasing the number of units that may be granted, subject to unitholder approval as required by the NYSE rules. However, no change in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant. The LTIP will terminate on the earliest of i) its termination by the Board or the Compensation Committee, ii) the tenth anniversary of the date the LTIP was adopted or iii) when units are no longer available for delivery pursuant to awards under the LTIP. Unless expressly provided for in the LTIP or an applicable award agreement, any award granted prior to the termination of the LTIP, and the authority of the Board or the Compensation Committee to amend, adjust or terminate such award or to waive any conditions or rights under such award, will extend beyond the termination date.

Assumed JPE Equity Plan

Pursuant to the JPE Merger, we assumed the JP Energy Partnership 2014 Long-Term Incentive Plan, which will be renamed the American Midstream Partners, LP Amended and Restated 2014 Long Term Incentive Plan (the "Assumed LTIP"). As of March 9, 2017, there were 312,736 Common Units available for awards under the Assumed Plan, as adjusted to reflect the JPE Merger. Following the JPE Merger, we plan to settle the existing awards made under the Assumed LTIP with the Common Units reserved under the Assumed LTIP.

Potential Payments Upon Termination or Change in Control

Employment Agreement with Lynn L. Bourdon III

The employment agreement with Lynn L. Bourdon III provides for, among other things, the payment of severance benefits following certain terminations of employment by our General Partner or the termination of employment by Mr. Bourdon for "Good Reason" (as defined below). If Mr. Bourdon's employment is terminated by our General Partner other than for "Cause" (as defined below) or other than on Mr. Bourdon's death or disability, or if Mr. Bourdon terminates his employment for Good Reason, Mr. Bourdon will receive a cash amount equal to his annual base salary in effect on the date of terminations plus the amount of his current year annual cash bonus for the year of termination at the target calculated as if all goals for a target bonus have been achieved. In these circumstances, Mr. Bourdon would also receive certain medical premium reimbursements and either accelerated or continued vesting of certain equity incentive awards. The severance benefits contained in his employment agreement are conditioned on Mr. Bourdon executing a release of claims in favor of our General Partner and its affiliates, including the Partnership. In the event that such a termination of his employment occurs within two years after a change in control, Mr. Bourdon may be entitled to receive two times the severance amount.

- "Cause" means Executive has (i) engaged in gross negligence in the performance of the duties required of him; (ii) engaged in willful misconduct in the performance of the duties required of him resulting in a material detriment to our General Partner; (iii) unlawfully used (including being under the influence of) or possessed illegal drugs on our General Partner's (or any of its affiliate's) premises or while performing his duties or responsibilities; (iv) committed a material act of fraud or embezzlement against our General Partner, its affiliates, or any of their respective equityholders; (v) been convicted of (or pleaded guilty or no contest to) a felony, other than a non-injury vehicular offense, that could be reasonably expected to reflect unfavorably and materially on our General Partner; or (vi) materially breached or violated any material provision of the agreement or violated any material provision of any material written company policy that has been previously provided or made available to Executive.
- "Good Reason" means, in connection with or based upon a nonconsensual (i) material alteration in Executive's responsibilities, duties, authority or titles or the assignment to Executive of duties or responsibilities inconsistent with Executive's status and titles as the most senior officer of our General Partner; (ii) assignment of Executive to a principal office located beyond a 30-mile radius of Executive's then current work place; or (iii) material breach by any

party to the agreement other than Executive of any material provision of the agreement.

The employment agreement provides that for a period of twelve months following a termination of employment by Mr. Bourdon for Good Reason (or nine months following a termination of employment of Mr. Bourdon by our General Partner or Mr. Bourdon due to the Company's non-renewal of the employment agreement or a termination of employment by the Company without Cause), Mr. Bourdon will be subject to a non-competition covenant. Furthermore, if our General Partner elects to pay Mr. Bourdon a cash amount equal to half of the severance amount following a termination of Mr. Bourdon's employment by our General Partner for

Cause or by Mr. Bourdon without Good Reason, then Mr. Bourdon will be subject to a six month non-competition covenant. Mr. Bourdon is also subject to a non-solicitation covenant for a period of twelve months following the termination of his employment.

Mr. Bourdon has received an award of phantom units under the LTIP. The terms of the phantom unit award agreement provide that a termination without Cause, for Good Reason, or due to death or disability, results in full acceleration of vesting of any outstanding phantom units.

Severance Agreement with Eric T. Kalamaras

Mr. Kalamaras' offer letter for his employment as our Chief Financial Officer provides for the payment of severance benefits following certain terminations of employment by our General Partner. Under the terms of the offer letter, if Mr. Kalamaras' employment is terminated by the General Partner other than for "Cause" (as defined below) prior to July 11, 2017, Mr. Kalamaras will have the right to severance in an amount equal to twelve months of his base salary plus the amount, if any, paid to him as an annual cash bonus for the calendar year 2016. The foregoing severance benefit is conditioned on Mr. Kalamaras executing a release of claims in favor of our General Partner and its affiliates, including us, and his compliance with the provisions regarding protection of confidential information, non-competition and non-solicitation outlined in Mr. Kalamaras' offer letter.

"Cause" is defined in Mr. Kalamaras' offer letter as Mr. Kalamaras having (A) engaged in gross negligence, gross incompetence or willful misconduct in the performance of the duties required of him in connection with his employment by the General Partner; (B) refused without proper reason to perform the duties and responsibilities required of him in connection with his employment by the General Partner; (C) willfully engaged in conduct that is materially injurious to the General Partner or its affiliates (which term includes, without limitation, the Partnership) (monetarily or otherwise); (D) committed an act of fraud, embezzlement or willful breach of fiduciary duty to the General Partner or its affiliates (including the unauthorized disclosure of confidential or proprietary material information of the Company or its affiliates); (E) alcohol or substance abuse that has impaired or could reasonably be expected to impair his ability to perform the duties and responsibilities required of him in connection with his employment by the General Partner; (F) failure to comply with the General Partner's or the Partnership's policies in any material respect (including those regarding harassment and discrimination) or (G) been convicted of (or pleaded no contest to) a crime involving fraud, dishonesty, moral turpitude or any felony.

The foregoing severance benefit is conditioned on Mr. Kalamaras executing a release of claims in favor of our General Partner and its affiliates, including us, his compliance with the provisions regarding protection of confidential information and his agreement to a one-year non-competition period and a one-year non-solicitation period.

Severance Agreement with Regina L. Gregory

Ms. Gregory's offer letter for her employment as our Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary provides for the payment of severance benefits following certain terminations of employment by our General Partner. Under the terms of the offer letter, if Ms. Gregory's employment is terminated by the General Partner other than for "Cause", Ms. Gregory will have the right to severance in an amount equal to twelve months of her base salary plus the amount, if any, paid to her as an annual cash bonus for the prior calendar year. The foregoing severance benefit is conditioned on Ms. Gregory executing a release of claims in favor of our General Partner and its affiliates, including us, and her compliance with the provisions regarding protection of confidential information, non-competition and non-solicitation outlined in Ms. Gregory's offer letter.

"Cause" is defined in Ms. Gregory's offer letter as Ms. Gregory having (A) engaged in gross negligence, gross incompetence or willful misconduct in the performance of the duties required of her in connection with her employment by the general partner; (B) refused without proper reason to perform the duties and responsibilities required of her in connection with her employment by the general partner; (C) willfully engaged in conduct that is materially injurious to the general partner or its affiliates (which term includes, without limitation, the Partnership) (monetarily or otherwise); (D) committed an act of fraud, embezzlement or willful breach of fiduciary duty to the general partner or its affiliates (including the unauthorized disclosure of confidential or proprietary material information of the general partner or its affiliates); (E) alcohol or substance abuse that has impaired or could reasonably be expected to impair her ability to perform the duties and responsibilities required of her in connection with her employment by the general partner; (F) failure to comply with the general partner's or the Partnership's policies in any material respect (including those regarding harassment and discrimination) or (G) been convicted of (or pleaded no contest to) a crime involving fraud, dishonesty, moral turpitude or any felony.

Separation Agreement with Michael D. Suder

Effective November 21, 2016, Michael D. Suder resigned as President and Chief Executive Officer of American Midstream Terminaling, LLC, American Midstream Blackwater, LLC, Blackwater Investments, Inc., Blackwater Midstream Corp., Blackwater New Orleans, L.L.C., Blackwater Georgia, L.L.C., Blackwater Maryland, L.L.C. and Blackwater Harvey, LLC, all wholly-owned, indirect subsidiaries of the Partnership. In connection with the resignation, the Partnership and Mr. Suder entered into a Separation Agreement and Release and Waiver (the "Suder Separation Agreement"), pursuant to which the Partnership agreed to pay Mr. Suder $300,000 in bi-weekly installments for 52 weeks. Additionally, during the 12-month period following November 21, 2016, to the extent that Mr. Suder is eligible for and elects to continue coverage under the Partnership's medical, vision and dental benefit plans, the Partnership will pay to the benefit administrator on behalf of Mr. Suder an amount equal to the amount the Partnership contributes towards the cost of coverage for a similarly situated active employee. The Suder Separation Agreement also terminates the employment agreement by and between the Partnership and Mr. Suder originally entered into on October 9, 2012, except that Mr. Suder must continue to comply with certain provisions related to the protection of confidential information under such agreement. There were no disagreements between Mr. Suder and the General Partner, the Partnership or any officer or Director of the General Partner which led to Mr. Suder's resignation.

Each of Messrs. Bourdon and Kalamaras and Ms. Gregory has received an award of phantom units under the LTIP. The terms of the phantom unit award agreements of these named executive officers provide that a termination due to death or disability results in full acceleration of vesting of any outstanding phantom units.
The following table shows the value of the severance benefits and other benefits for the named executive officers under the employment agreements and phantom unit grant agreements at December 31, 2016:

Name	Benefit Type	Death or Disability	Before Change in Control Termination without cause or for Good Reason or upon expiration	After Change in Control Termination without cause or for Good Reason or upon expiration	Certain Changes of Control (3)
Lynn L. Bourdon III	Severance payment per employment agreement (2) (4)	None	$1,000,000	$2,000,000	None
	COBRA payment per employment agreement.	None	$18,870	$18,870	None
	Accelerated vesting of phantom unit awards per award agreement (1)	$7,244,764	$7,244,764	$7,244,764	$7,244,764
	Accelerated vesting of options awards per award agreement (1)	$2,140,000	$2,140,000	$2,140,000	$2,140,000
	Total	$9,384,764	$10,403,634	$11,403,634	$9,384,764
Eric T. Kalamaras	Severance payment per offer (5)	None	$285,000	$285,000	None
Regina L. Gregory	Severance payment per offer	None	$275,000	$275,000	None
	Accelerated vesting of phantom unit awards per award agreement (6)	$819,000	None	None	None

Total	$819,000	$275,000	$275,000

(1) The amounts shown in this row are calculated based on the fair market value of our Common Units which we have assumed were $18.20, which was the closing price of our Common Units on December 31, 2016, multiplied by the number of

115

phantom units that would have vested as of December 31, 2016. The market value of the Option Grant that has not vested as of December 31, 2016 for Mr. Bourdon is $10.70, per Common Unit subject to the option, which is the difference between the closing price of our Common Units on December 31, 2016 and the exercise price.

(2) In connection with a termination of the executive's employment upon expiration of the initial or extended term of the agreement by either party pursuant to the terms of the employment agreement, the Board may, in its discretion, release the executive from being subject to the non-competition covenant following termination of employment; however, in such case, the executive would not be entitled to receive the severance payment.

(3) Pursuant to the employment agreement, accelerated vesting of all unvested long-term equity incentive awards under the LTIP would only occur under certain types of change of control transactions.

(4) In the event that Mr. Bourdon is terminated without cause or resigns for Good Reason within two years after a change in control, Mr. Bourdon may be entitled to receive two times the severance amount or $2,000,000.

(5) This individual is an at will employee and does not have an employment agreement that would trigger any payment upon expiration of its term or upon termination by the employee for Good Reason.

(6) The amounts shown are calculated based on the fair market value of our Common Units which we have assumed were $18.20, which was the closing price of our Common Units on December 31, 2016, multiplied by the number of phantom units that would have vested as of December 31, 2016.

Compensation of Directors

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the Board was comprised of Messrs. Bourdon and Erhard as of December 31, 2016. The Compensation Committee makes compensation decisions regarding the executive officers of our General Partner. With the exception of Mr. Bourdon, none of the members of the Compensation Committee is or has been one of our officers or employees, and none of our executive officers served during 2016 on a board of directors or compensation committee of another entity which has employed any of the members of our Board or Compensation Committee.

Director Fees

Each director who is not an officer or employee of our General Partner receives compensation for attending meetings of the Board of Directors, as well as committee meetings, as follows:

- a $50,000 annual cash retainer;
- a $50,000 annual unit grant;
- where applicable, a variable fee for service rendered as member of the Conflicts Committee to the Board; and
- where applicable, a committee chair retainer of $10,000 for each committee chaired.

In addition, each non-employee director will receive per meeting fees of:

- $1,000 for meetings attended in person;
- where applicable, $500 for committee meetings attended in person; and
- $500 for telephonic meetings and committee meetings greater than one hour in length.

Generally, non-employee directors listed in the table below are reimbursed for out-of-pocket expenses in connection with attending meetings of the Board of Directors or its committees. Each director will be fully indemnified by us for actions associated with being a director of our General Partner to the extent permitted under Delaware law.

Director Compensation Table for 2016

The following table sets forth the compensation paid to our non-employee directors for the year ended December 31, 2016, as described above. The compensation paid in 2016 to Mr. Bourdon as an executive officer is set forth in the summary compensation tables above. Mr. Bourdon did not receive any additional compensation related to his service as a director.

	Fees Earned or Paid in Cash	Unit Awards (1)	All Other Compensation	Total Compensation
Stephen W. Bergstrom	$ 26,250	$ 26,250	$ —	$ 52,500
John F. Erhard	—	—	—	—
Donald R. Kendall Jr.	60,250	60,250		120,500
Daniel R. Revers	—	—	—	—
Rose M. Robeson	44,415	44,415		88,830
Peter A. Fasullo	16,585	16,585		33,170
Joseph W. Sutton	—	—	—	—
Lucius H. Taylor	—	—	—	—
Gerald A. Tywoniuk	68,250	68,250		136,500

(1) The amount reported in this column represents the aggregate grant date value of the unit award granted during 2016.

Compensation Committee Report

During 2016, the Compensation Committee of the Board was comprised of two directors (Messrs. Bourdon and Erhard).

The Compensation Committee has discussed and reviewed the above Compensation Discussion and Analysis for fiscal year 2016 with management. Based on this review and discussion, the Compensation Committee recommended to the Board that this Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year 2016.

Lynn L. Bourdon III
John F. Erhard

Compensation Practices as They Relate to Risk Management

We do not believe that our compensation policies and practices create risks that are reasonably likely to have a material adverse effect on the Partnership. We believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees). Short-term annual incentives are generally paid pursuant to discretionary bonuses enabling the CEO and Compensation Committee to assess the actual behavior of our employees as it relates to risk taking in awarding a bonus. Our use of equity based long-term compensation serves our compensation program's goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk taking.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth certain information regarding the beneficial ownership of units as of March 20, 2017 and the related transactions by:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding;
- our General Partner;
- each of the directors and named executive officers of our General Partner; and
- all of the directors and executive officers of our General Partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders as the case may be.

Our General Partner is owned 77% by HPIP and 23% by Magnolia Infrastructure Holding, LLC, both controlled by ArcLight.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of March 20, 2017, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned		Preferred Series A Units Beneficially Owned	Preferred Series C Units Beneficially Owned	Preferred Series D Units Beneficially Owned	Percentage of Total Common Units Beneficially Owned on a Fully Converted Basis (8)	
ArcLight Capital Partners, LLC (1)	13,977,709	27.1	%	10,266,642	8,792,205	2,333,333	49.2	%
Swank Capital, LLC (2)	2,557,100	5.0	%	—	—	—	3.5	%
Oppenheimer Funds, Inc. (3)	5,402,942	10.5	%	—	—	—	7.3	%
Lynn L. Bourdon III (4)	150,042	*		—	—	—	*	
Eric T. Kalamaras (4)	—	*		—	—	—		
Daniel C. Campbell (4)	40,970	*		—	—	—	*	
Regina L. Gregory	—	*		—	—	—		
Michael D. Suder (4) (5)	70,210	*		—	—	—	*	
Matthew W. Rowland (4) (5)	50,500	*		—	—	—	*	
Ryan K. Rupe	16,983	*		—	—	—	*	
William B. Mathews (5)	99,532	*		—	—	—	*	
Daniel R. Revers (1)(2)(4)	13,977,709	27.1	%	10,266,642	8,792,205	2,333,333	49.2	%
John F. Erhard (4)	—	*		—	—	—	*	
Stephen W. Bergstrom (4)	47,023	*		—	—	—	*	
Donald R. Kendall Jr. (4)	27,275	*		—	—	—	*	
Peter A. Fasullo (4)(6)	5,605	*		—	—	—	*	
Joseph W. Sutton (4)	—	*		—	—	—	*	
Lucius H. Taylor (4)	—	*		—	—	—	*	
Gerald A. Tywoniuk (5)(7)	24,231	*		—	—	—	*	
All directors and executive officers as a group (consisting of 19 persons)	14,291,904	27.7	%	10,266,642	8,792,205	2,333,333	49.6	%

118

* An asterisk indicates that the person or entity owns less than one percent.

Includes 7,187,358 Series A-1 Convertible Preferred Units ("Series A-1 Units") held by High Point Infrastructure Partners,
LLC ("High Point"), convertible into 7,925,500 common units of the Issuer ("Common Units"), which are indirectly owned by Magnolia Infrastructure Partners, LLC ("Magnolia"), 3,079,284 Series A-2 Convertible Preferred Units ("Series A-2 Units") held by Magnolia, convertible into 3,395,526 Common Units, 8,792,205 Series C Convertible Preferred Units ("Series C Units") held by Magnolia Infrastructure Holdings, LLC ("Magnolia Holdings"), convertible into 8,823,857 Common Units, 2,333,333 Series D Convertible Preferred Units ("Series D Units") held directly by Magnolia Holdings convertible into 2,333,333 Common Units, 9,753,425 Common Units held by Magnolia Holdings 1,349,609 Common Units held by American Midstream GP, LLC, which is approximately 77% owned by High Point and approximately 23% owned by Magnolia Holdings, 618,921 Common Units held by Magnolia and 2,255,754 Common Units held by Busbar II, LLC ("Busbar").

(1) ArcLight Capital Holdings, LLC ("ArcLight Holdings") is the sole manager and member of ArcLight Capital Partners, LLC. ArcLight Holdings is the investment adviser to ArcLight Energy Partners Fund V, L.P. ("Fund V") and ArcLight PEF GP V, LLC ("Fund GP") is the general partner of Fund V. HPIP is controlled by Magnolia, which is in turn controlled by Fund V. Busbar is a wholly owned, direct subsidiary of Fund V (collectively, Busbar HPIP, Magnolia, Fund V, Fund GP, ArcLight Holdings and ArcLight are the "ArcLight Entities"). ArcLight is the manager of the general partner of Fund V. Mr. Daniel R. Revers is a manager of ArcLight Holdings and a managing partner of ArcLight and has certain voting and dispositive rights as a member of ArcLight's investment committee. Fund V, through indirectly controlled subsidiaries, owns approximately 90% of the ownership interest in HPIP. As a result, the ArcLight Entities and Mr. Revers may be deemed to indirectly beneficially own the securities of the Partnership held by HPIP and our General Partner, but disclaim beneficial ownership except to the extent of their respective pecuniary interests therein. The address for this person or entity is 200 Claredon Street, 55th Floor, Boston, MA 02117. This information is based solely on information included in the Schedule 13D/A filed by the beneficial owner on March 14, 2017.

(2) The common units were purchased by Cushing Asset Management, LP, a Texas limited partnership ("Cushing Management"), through the accounts of certain private funds and managed accounts (collectively, the "Cushing Accounts"). Cushing Management serves as the investment adviser to the Cushing Accounts and may direct the vote and dispose of the 2,557,100 Common Units held by the Cushing Accounts. Swank Capital, L.L.C. ("Swank Capital") serves as the general partner of Cushing Management and may direct Cushing Management to direct the vote and disposition of the 2,557,100 Common Units held by the Cushing Accounts. As the principal of Swank Capital, Mr. Jerry V. Swank may direct the vote and disposition of the 2,557,100 Common Units held by the Cushing Accounts. The address for such persons is 8117 Preston Road, Suite 440, Dallas, Texas 75225. This information is based solely on information included in the Schedule 13G filed by the beneficial owner on February 14, 2017.

(3) The Oppenheimer Funds, Inc. ("Oppenheimer") is an investment adviser in accordance with Rule 13d-1(b)(1)(ii)(E). Oppenheimer shares voting and dispositive power over 5,402,942 Common Units with Oppenheimer SteelPath MLP Income Fund ("Oppenheimer SteelPath"), which is an investment company registered under Section 8 of the Investment Company Act of 1940.The address for these entities is Two World Financial Center, 225 Liberty Street, New York, NY 10281. This information is based solely on information included in the Schedule 13G filed by the beneficial owner on February 1, 2016.

(4) The address for this person or entity is c/o American Midstream Partners, LP, 2103 CityWest Blvd, Bldg. 4, Suite 800, Houston, TX 77042.

(5) This information is based solely the latest Form 4 filed for this beneficial owner.

(6) Includes 5,605 Common Units held in Fasullo Family Revocable Trust, for which Mr. Fasullo is the trustee.

(7) Includes 22,231 Common Units held in The Gerald Allen Tywoniuk Trust dated June 25, 2010, for which Mr. Tywoniuk is the trustee.

(8) The percentage of units beneficially owned is based on a total of 51,585,690 common units and 10,266,642 Series A Units, 8,792,205 Series C Units, and 2,333,333 Series D Units, as applicable, outstanding at March 20, 2017.

Securities Authorized for Issuance Under Equity Compensation Plans

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 2, 2009, the Board of Directors of our General Partner adopted a long-term incentive plan for its employees, consultants and directors who perform services for it or its affiliates. On May 25, 2010, the Board of Directors of our General Partner adopted an Amended and Restated Long-Term Incentive Plan. On July 11, 2012, the Board of Directors of our General Partner adopted a Second Amended and Restated Long-Term Incentive Plan that effectively increased available awards by 871,750 units. On November 19, 2015, the Board of Directors of our General Partner approved the Third Amended and Restated Long-Term Incentive Plan, which, subject to unitholder approval, would increase the number of common units authorized for issuance by 6,000,000 common units. On February 11, 2016, the unitholders approved the Third Amended and Restated Long-Term Incentive Plan to increase available awards by 6,000,000 common units. At December 31, 2016, 2015 and 2014, there were 5,017,528; 15,484; and

688,976 common units, respectively, available for future issuance under the LTIP. In addition, the information provided under "Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities" is incorporated by reference.

Item 13. Certain Relationships and Related Transactions and Director Independence

As of March 20, 2017, HPIP controlled and owned 77% of the General Partner of the Partnership, and Magnolia Infrastructure Holdings, LLC owned 23%, of our General Partner, which owned an approximate 1.3% General Partner interest in us and all of our incentive distribution rights. HPIP and Magnolia Infrastructure Partners ("MIP") hold 7,187,358 Series A-1 Units and 3,079,284 Series A-2 Units, respectively, and control our General Partner which held 1,349,609 common units.

Distributions and Payments to our General Partner and its Affiliates

The following summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation and any liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Distributions of available cash to our General Partner and its affiliates:

HPIP, as the holder of 7,187,358 Series A-1 Units, MIP (an affiliate of HPIP), as the holder of 3,079,284 Series A-2 Units, and Magnolia Infrastructure Holdings, LLC (an affiliate of HPIP), as the holder of 8,792,205 Series C Units, are entitled to receive cumulative distributions consisting of cash and Series A and C PIK preferred units, respectively, prior to any other distributions made in respect of any other partnership interests (the "Series A and C Quarterly Distribution") in accordance with our Partnership Agreement, as amended (the "Partnership Agreement"). With respect to the coupon conversion quarter (as defined in our Partnership Agreement) and all quarters thereafter, the Series A Quarterly Distribution shall be paid entirely in cash in accordance with our Partnership Agreement. To the extent that any portion of a Series A Quarterly Distribution to be paid in cash with respect to any quarter exceeds the amount of available cash for such quarter, an amount of cash equal to the available cash for such quarter will be paid to the Series A and C unitholders and the balance of such Series A and C Quarterly Distribution shall be unpaid, constitute an arrearage and accrue interest.

After making the Series A and C convertible preferred quarterly distribution and paying any arrearage and accrued interest with respect to the Series A Units, we will distribute available cash from operating surplus for any quarter 98.7% to our common unitholders, and 1.3% to our General Partner in respect of its general partnership interest, assuming it makes any capital contributions necessary to maintain its 1.3% General Partner interest in us. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, the holders of our incentive distribution rights will be entitled to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level.

Magnolia Infrastructure Holdings, LLC (an affiliate of HPIP), as the holder of 2,333,333 Series D Units is entitled to receive cumulative distributions consisting of cash, in the same priority as the Series A Units and the Series C Units and prior to any other distributions made in respect of any other partnership interests (the “Series D Quarterly Distribution”) in accordance with our Partnership Agreement.

Payments to our General Partner and its affiliates

Our General Partner will not receive a management fee or other compensation for its management of us. However, we will reimburse our General Partner and its affiliates for all expenses incurred on our behalf. Our Partnership Agreement provides that our General Partner will determine the amount of these reimbursed expenses.

Withdrawal or removal of our General Partner

If our General Partner withdraws or is removed, its General Partner interest and its incentive distribution rights will either be sold to the new General Partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Upon our liquidation, our partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Ownership Interests of Certain Executive Officers and Directors of Our General Partner

HPIP controls and owns 77%, and Magnolia Infrastructure Holdings, LLC owns 23%, of our General Partner.

In addition to the approximate 1.3% General Partner interest in us, our General Partner owns the incentive distribution rights, which entitle the holder to increasing percentages, up to a maximum of 48.0%, of the cash we distribute in excess of $0.4125 per unit per quarter.

Agreements with Affiliates

We and other parties have or may enter into the various documents and agreements with certain of our affiliates, as described in more detail below. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's-length negotiations.

Business Development Activity. For the years ended December 31, 2016, 2015 and 2014, our General Partner incurred approximately $0.8 million, $1.5 million, and $0.9 million respectively, of costs related to business development compensation that were funded by the Partnership. As of December 31, 2016, the Partnership has been reimbursed for these costs. For the years ended December 31, 2016, 2015 and 2014, our General Partner incurred approximately less than $0.1 million, $0.1 million and $0.1 million of costs associated with other business development activities, respectively. If the business development activities result in a project that will be pursued and funded by the Partnership, we will reimburse our General Partner for the business development costs related to that project.

Related Party Transactions

Michael D. Rupe, the brother of Ryan Rupe (AMID’s Vice President - Natural Gas Services and Offshore Pipelines), is the Chief Financial Officer of CIMA Energy Ltd., a crude oil and natural gas marketing company (“CIMA”). AMID regularly engages in purchases and sales of crude oil and natural gas with CIMA. During fiscal year 2016, AMID paid $4.3 million to CIMA and CIMA paid AMID $3.6 million in connection with such transactions.

On April 25, 2015, we issued 8,571,429 Series C Units to Magnolia Infrastructure Holdings, LLC, an ArcLight affiliate (“Magnolia Holdings”), and a warrant to purchase 800,000 common units in a private placement for approximately $120.0 million in gross proceeds. All of the proceeds of the offering plus additional borrowings of $91.0 million under our Credit Agreement were paid to Emerald Midstream, LLC, an ArcLight affiliate, for the Emerald Transactions.

On October 31, 2016, we issued the 2,333,333 Series D Units to Magnolia Holdings in a private placement for $15.00 per unit, less a closing fee of 1.5%, for approximately $34.4 million in net proceeds. If any Series D Units remain outstanding on June 30, 2017, the Partnership will issue a warrant to purchase up to 700,000 common units representing limited partnership interests in the Partnership at an exercise price of $22.00 per common unit.

Procedures for Review, Approval and Ratification of Related-Person Transactions

The Board has adopted a code of business conduct and ethics that provides that the Board of Directors of our General Partner or its authorized committee will periodically review all related-person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the Board of Directors of our General Partner or its authorized committee considers ratification of a related-person transaction and determines not to so ratify, the code of business conduct and ethics will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The Code of Ethics provides that, in determining whether to recommend the initial approval or ratification of a related-person transaction, the Board of Directors of our General Partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: i) whether there is an appropriate business justification for the transaction; ii) the benefits that accrue to us as a result of the transaction; iii) the terms available to unrelated third parties entering into similar transactions; iv) the impact of the transaction on director independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, shareholder, member or executive officer); v) the availability of other sources for comparable products or services; vi) whether it is a single transaction or a series of ongoing, related transactions; and vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

The Code of Ethics described above was adopted in connection with the closing of our initial public offering, and as a result the transactions described above were not reviewed under such policy.

In addition, our Partnership Agreement provides for the Conflicts Committee, as delegated by the Board as circumstances warrant, to review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. If a matter is submitted to the Conflicts Committee, which will consist solely of independent directors, for their review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the Board of Directors of our General Partner is fair and reasonable to us. The members of the Conflicts Committee may not be executive officers or employees of our General Partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders.

Item 14. Principal Accountant Fees and Services

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed or expect to be billed by PricewaterhouseCoopers LLP for audit, audit-related, tax and other services for each of the last two years:

	Years Ended December 31,	
	2016	2015
	(in thousands)	
Audit fees (1)	$1,994	$1,308
Audit related fees (2)	409	24
Tax fees (3)	332	325
All other fees (4)	—	—
	$2,735	$1,657

(1) Audit fees relate to professional services provided in connection with audits of our annual financial statements and internal control over financial reporting; reviews of our interim financial statements; audits of the annual financial statements of certain of our subsidiaries or affiliates pursuant to regulatory or contractual requirements; and, services provided in connection with the Partnership’s filings with the U.S. Securities and Exchange Commission, including the issuance of comfort letters and consents.

(2) Audit-related fees relate to professional services provided for accounting consultations as well as assurance services relating to proposed transactions.

(3) Tax fees relate to professional services provided in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of K-1 statements for our unitholders.

(4) All other fees relate to professional services provided which do not fit into one of the preceding categories.

Our Audit Committee approved the use of PricewaterhouseCoopers LLP as our independent registered public accounting firm to conduct the audit of our consolidated financial statements for the year ended December 31, 2016. All services provided by our independent auditor are subject to pre-approval by the Audit Committee. The Audit Committee is informed of each engagement of the independent auditor to provide services to us.

PART IV

Item 15. Exhibits and Financial Statement Schedules
(a)(1) Financial Statements
Our consolidated financial statements are included under Part II, Item 8 of the Annual Report. For a listing of these items and accompanying footnotes, see "Index to Financial Statements": beginning on Page F-1 of this Annual Report.
(a)(2) Financial Statement Schedules
All other schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto or will be filed within the required timeframe.
(a)(3) Exhibits

1.1	ATM Equity Offering Sales Agreement by and among Merrill Lynch, Pierce, Fenner & Smith, Inc., SunTrust Robinson Humphrey, Inc., American Midstream Partners, L.P., American Midstream GP, LLC and American Midstream, LLC (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed on October 10, 2015 [File No. 001-35257])
2.1	Purchase and Sale Agreement by and between Toga Offshore, LLC and American Midstream Delta House, LLC, dated August 10, 2015 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on August 12, 2015 [File No. 001-35257])
2.2	Purchase and Sale Agreement, dated October 13, 2014, by and among American Midstream, LLC, Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed October 15, 2014 [File No. 001-35257]).
2.3	Purchase and Sale Agreement by and between Emerald Midstream, LLC and American Midstream Emerald, LLC, dated April 25, 2016 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 29, 2016 File [No. 001-35257])
2.4	Purchase and Sale Agreement by and between Emerald Midstream, LLC and American Midstream Emerald, LLC, LLC, dated April 27, 2016 (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed on April 29, 2016 [File No. 001-35257])
2.5	Purchase Agreement by and between Magnolia Infrastructure Holdings, LLC and American Midstream Delta House, LLC, dated April 25, 2016 (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K filed on April 29, 2016 [File No. 001-35257])
2.6	Agreement and Plan of Merger, by and between American Midstream Partners, LP, American Midstream GP, LLC, JP Energy Partners LP, JP Energy GP II LLC, Argo Merger Sub, LLC and Argo Merger GP Sub, LLC dated October 23, 2016 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on October 24, 2016 [File No. 001-35257])
2.7	Unit Purchase Agreement by and between Red Willow Offshore, LLC and D-Day Offshore Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on November 11, 2016 [File No. 001-35257])
2.8	Unit Purchase Agreement by and between ILX Prospect Niedermeyer, LLC and D-Day Offshore Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed on November 11, 2016 [File No. 001-35257])

2.9	Unit Purchase Agreement by and between ILX Prospect Diller, LLC and D-Day Offshore Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K filed on November 11, 2016 [File No. 001-35257])
2.10	Unit Purchase Agreement by and between ILX Prospect Marmalard, LLC and D-Day Offshore Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 2.4 to the Current Report on Form 8-K filed on November 11, 2016 [File No. 001-35257])
2.11	Unit Purchase Agreement by and between LLOG Bluewater Holdings, L.L.C. and D-Day Offshore Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 2.5 to the Current Report on Form 8-K filed on November 11, 2016 [File No. 001-35257])
2.12	Unit Purchase Agreement by and between Ridgewood Energy Investment Funds and D-Day Offshore Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 2.6 to the Current Report on Form 8-K filed on November 11, 2016 [File No. 001-35257])
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form S-1 filed March 31, 2011 [File No. 333-173191])
3.2	Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form 8-K filed August 15, 2013 [File No 001-35257])
3.3	First Amendment to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form 8-K filed November 1, 2013 [File No. 001-35257])
3.4	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP. (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP, Form 8-K filed February 4, 2014 [File No. 001-35257])
3.5	Amendment No. 3 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, L.P., dated January 31, 2014 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 6, 2014 [File No. 001-35257])
3.6	Amendment No. 4 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, L.P., dated March 30, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed March 31, 2015 [File No. 001-35257])
3.7	Amendment No. 5 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, L.P., dated July 27, 2015 (incorporated by reference Exhibit 3.1 to the Current Report on Form 8-K filed on July 28, 2015 [File No. 001-35257])
3.8	Amendment No. 6 to Fourth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, L.P., dated September 9, 2015 (incorporated by reference to Exhibit 3.1 the Current Report on Form 8-K filed on November 9, 2015 [File No. 001-35257])
3.9	

Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to American Midstream Partners, LP, Form S-1 filed March 31, 2011 [File No. 333-173191])

124

3.10	Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to American Midstream Partners, LP Form 8-K filed April 19, 2013 [File No. 000-35257])
3.11	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.1 to American Midstream Partners, LP Form 8-K filed February 10, 2014 [File No.001-35257])
3.12	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC, dated August 7, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on August 12, 2015 [File No. 001-35257])
3.13	Amendment No. 3 to Second Limited Liability Company Agreement of American Midstream GP, LLC, dated November 3, 2015 (incorporated by reference Exhibit 3.2 to the Current Report on Form 8-K filed on November 9, 2015 [File No. 001-35257])
3.14	Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP dated April 25, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on April 29, 2016 [File No. 001-35257])
3.15	Third Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC, dated May 2, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on May 6, 2016 [File No. 001-35257])
3.16	Amendment No. 1 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP dated April 25, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on June 22, 2016 [File No. 001-35257])
3.17	Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP dated April 25, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on November 4, 2016 [File No. 001-35257])
3.18	Amendment No. 3 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP dated April 25, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on March 8, 2017 [File No. 001-35257])
3.19*	Composite Agreement of Limited Partnership of American Midstream Partners, LP
4.1	Securities Agreement, dated October 13, 2014, by and among American Midstream Partners, LP, Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 15, 2014 [File No. 001-35257])
10.1	Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among American Midstream Partners, LP, American Midstream, LLC, Blackwater Investments, Inc., Bank of America, N.A., Wells Fargo Bank, National Association, BBVA Compass, Capital One National Association, Citicorp North America, Inc., Comerica Bank, SunTrust Bank, Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed September 10, 2014 [File No. 001-35257])

10.2	Third Amended and Restated American Midstream GP, LLC Long-Term Incentive Plan (incorporated by reference to Appendix A of the Registrant's Definitive Proxy Statement on Schedule 14A filed on January 11, 2016 (File No. 001-35257

10.3	Form of American Midstream Partners, LP Long-Term Incentive Plan Grant of Phantom Units (incorporated by reference to Exhibit 10.8 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.4	Gas Processing Agreement between American Midstream (Louisiana Intrastate), LLC, and Enterprise Gas Processing, LLC, dated June 1, 2011 (incorporated by reference to Exhibit 10.9 to American Midstream Partners, LP Form S-1/A filed July 15, 2011 [File No. 333-173191])
10.5	Firm Gas Gathering Agreement Between American Midstream (Seacrest) LP, and Contango Resources Company (incorporated by reference to Exhibit 10.10 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191])
10.6	Amendment to Firm Gas Gathering Agreement between American Midstream Offshore (Seacrest) LP (formerly Enbridge Offshore Pipelines [Seacrest [L.P.), and Contango Operators, Inc. (formerly Contango Resources Company) dated as of August 1, 2008 (incorporated by reference to Exhibit 10.11 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191])
10.7	Base Contract for Sale and Purchase of Natural Gas Between Exxon Gas & Power Marketing Company and Mid Louisiana Gas Transmission, LLC (incorporated by reference to Exhibit 10.12 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191])
10.8	Gas Processing Agreement Between American Midstream (Mississippi) LLC and Venture Oil and Gas, Inc. (incorporated by reference to Exhibit 10.13 to American Midstream Partners, LP, Form S-1/A filed June 2, 2011 [File No. 333-173191])
10.9	Gas Transportation Contract between Midcoast Interstate Transmission, Inc. and City of Decatur Utilities (incorporated by reference to Exhibit 10.14 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.10	Amendment No. 1 to Gas Transportation Contract between Enbridge Pipelines (AlaTenn) Inc. and the City of Decatur, Alabama (incorporated by reference to Exhibit 10.15 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.11	Natural Gas Pipeline Construction and Transportation Agreement between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.16 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 (File No. 333-173191))
10.12	First Amendment to Natural Gas Pipeline Construction and Transportation Agreement dated June 28, 2000 between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.17 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.13	Natural Gas Pipeline Transportation Agreement between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.18 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.14	First Amendment to Natural Gas Pipeline Transportation Agreement dated June 28, 2000 between Bamagas Company and Calpine Energy Services, L.P. (incorporated by reference to Exhibit 10.19 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.15	

	Gas Transport Contract between Enbridge Pipelines (AlaTenn), L.L.C., and the City of Huntsville (incorporated by reference to Exhibit 10.20 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.16	Service Agreement between Enbridge Pipelines (Midla), L.L.C., and Enbridge Marketing (US), LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.21 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])

10.17	Service Agreement between Enbridge Pipelines (Midla), L.L.C., and Enbridge Marketing (US), LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.22 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.18	Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC, and Enterprise Gas Processing, LLC, dated July 1, 2010 (incorporated by reference to Exhibit 10.23 to American Midstream Partners, LP Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.19	Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC, and Enterprise Gas Processing, LLC, dated November 1, 2010 (incorporated by reference to Exhibit 10.24 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.20	Gas Processing Agreement TOCA Gas Processing Plant between American Midstream, LLC, and Enterprise Gas Processing, LLC, dated April 1, 2011 (incorporated by reference to Exhibit 10.25 to American Midstream Partners, LP, Form S-1/A filed June 30, 2011 [File No. 333-173191])
10.21+	Form of Amendment of Grant of Phantom Units Under the American Midstream Partners, LP, Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to American Midstream Partners, LP, Form S-1/A filed June 9, 2011 [File No. 333-173191])
10.22+	Employment Agreement by and between American Midstream GP, LLC, and Daniel C. Campbell (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed April 16, 2012 [File No. 001-35257]).
10.23	Purchase and Sale Agreement, dated May 25, 2012, by and between Quantum Resources A1, LP, QAB Carried WI, LP, QAC Carried WI, LP and Black Diamond Resources, LLC, collectively as Seller and Quantum Resources Management, LLC, and American Midstream Chatom Unit 1, LLC, American Midstream Chatom Unit 2, LLC, collectively as Buyer (incorporated by reference to Exhibit 10.3 to American Midstream Partners, LP, Amendment No. 1 to Form 10-Q filed November 13, 2012 [File No. 001-35257]).
10.24	Contribution Agreement by and between High Point Infrastructure Partners, LLC, and American Midstream Partners, LP, dated April 15, 2013 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed April 19, 2013 [File No. 001-35257])
10.25	Equity Restructuring Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated August 9, 2013 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed August 15, 2013 [File No. 001-35257])
10.26+	Employment Agreement between Matthew W. Rowland and American Midstream GP, LLC, dated August 22, 2013 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed August 28, 2013 [File No. 001-35257])
10.27	Series B PIK Unit Purchase Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated January 22, 2014 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed January 22, 2014 [File No. 001-35257])
10.28	First Amendment to Series B PIK Unit Purchase Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC, and High Point Infrastructure Partners, LLC, dated January 22, 2014

	(incorporated by reference to Exhibit 10.2 to American Midstream Partners, LP, Form 8-K filed February 4, 2014 [File No. 001-35257])
10.29	Construction and Field Gathering Agreement by and between HPIP Lavaca, LLC, and Penn Virginia Oil & Gas, L.P., dated January 31, 2014 (incorporated by reference to Exhibit 10.1 to American Midstream Partners, LP, Form 8-K filed February 4, 2014 [File No. 001-35257])
10.30	Change of Control Severance Agreement, dated June 5, 2014, by and between American Midstream GP, LLC and Tom L. Brock (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2014 [File No. 001-35257])

10.31	Common Unit Purchase Agreement, dated July 14, 2014, by and among American Midstream Partners, LP and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed Jul 15, 2014 [File No. 001-35257])
10.32	Waiver of Condition and First Amendment to Common Unit Purchase Agreement, dated August 15, 2014 by and among American Midstream Partners, LP and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 20, 2014 [File No. 001-35257])
10.33	Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among American Midstream Partners, LP, American Midstream, LLC, Blackwater Investments, Inc., Bank of America, N.A., Wells Fargo Bank, National Association, BBVA Compass, Capital One National Association, Citicorp North America, Inc., Comerica Bank, SunTrust Bank, Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed September 10, 2014 [File No. 001-35257])
10.34	Series A-2 Convertible Preferred Unit Purchase Agreement by and between American Midstream Partners and L.P. and Magnolia Infrastructure Partners, LLC, dated March 30, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 31, 2015 [File No. 001-35257])
10.35	Second Series A-2 Convertible Preferred Unit Purchase Agreement by and between American Midstream Partners, L.P. and Magnolia Infrastructure Partners, LLC, dated June 30, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on July 2, 2015 [File No. 001-35257])
10.36	First Amendment and Incremental Commitment Agreement by and among American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, L.P., Bank of America, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference to the Current Report on Form 8-K filed on September 21, 2015 [File No. 001-35257])
10.37+	Employment Agreement by and between American Midstream GP, LLC and Michael D. Suder dated October 9, 2012
10.38+	Employment Agreement by and between American Midstream GP, LLC and Lynn L. Bourdon III, dated December 10, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 14, 2015 [File No. 001-35257])
10.39+	Phantom Unit Award Agreement by and between American Midstream GP, LLC and Lynn L. Bourdon III, dated December 10, 2015 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on December 14, 2015 [File No. 001-35257])
10.40+	Unit Purchase Option Grant Agreement by and between American Midstream GP, LLC and Lynn L. Bourdon III, dated December 10, 2015 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on December 14, 2015 [File No. 001-35257])
10.41+	First Amendment to Employment Agreement by and between American Midstream GP, LLC and Michael D. Suder dated November 4, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 9, 2015 [File No. 001-35257])
10.41+	

	Employment Agreement by and between American Midstream GP, LLC and Michael D. Suder dated December 13, 2015 (incorporated by reference to Exhibit 10.37 to the Annual Report on Form 10-K filed on March 7, 2016 [File No. 001-35257])
10.42+	Second Amendment to Employment Agreement by and between American Midstream GP, LLC and Michael D. Suder dated March 7, 2016 (incorporated by reference to Exhibit 10.37 to the Annual Report on Form 10-K filed on March 7, 2016 [File No. 001-352571])

10.43	Securities Purchase Agreement by and between American Midstream Partners, LP and Magnolia Infrastructure Holdings, LLC dated April 25, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on April 29, 2016 [File No. 001-35257])
10.44	Second Amendment to Amended and Restated Credit Agreement and First Amendment to Amended and Restated Guaranty and Collateral Agreement by and between American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP and Bank of America, N.A. dated April 25, 2016 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on April 29, 2016 [File No. 001-35257])
10.45	Form of Warrant to Purchase Common Units of American Midstream Partners, LP (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on April 29, 2016 [File No. 001-35257])
10.46	Class C Membership Interest Award Agreement by and between American Midstream GP, LLC and LB3 Services dated May 2, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 6, 2016 [File No. 001-35257])
10.47	Note Purchase and Guaranty Agreement by and between American Midstream Midla Financing, LLC, American Midstream (Midla), LLC, Mid Louisiana Gas Transmission, LLC and the other parties thereto dated September 30, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 6, 2016 [File No. 001-35257])
10.48	Limited Waiver and Third Amended and Restated Credit Agreement by and between American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP and Bank of America, N.A. dated September 30, 2016 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on October 6, 2016 [File No. 001-35257])
10.49	Distribution Support and Expense Reimbursement Agreement by and among American Midstream Partners, LP, American Midstream GP, LLC and Magnolia Infrastructure Holdings, LLC dated October 23, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 24, 2016 [File No. 001-35257])
10.50	Securities Purchase Agreement by and between American Midstream Partners, LP and Magnolia Infrastructure Holdings, LLC dated October 31, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 4, 2016 [File No. 001-35257])
10.51+	Unit Purchase Option Grant Notice dated August 26, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on November 8, 2016 [File No. 001-35257])
10.52+	Long-Term Incentive Plan Grant of Phantom Units dated July 26, 2016 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed on November 8, 2016 [File No. 001-35257])
10.53+	Transition and Release and Waiver Agreement between Daniel C. Campbell and American Midstream GP, LLC dated September 2, 2016 (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed on November 8, 2016 [File No. 001-35257])
10.54+	Letter from American Midstream GP, LLC to Eric Kalamaras dated July 6, 2016 (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed on November 8, 2016 [File No. 001-35257])

10.55+	Letter from American Midstream GP, LLC to Michael Croney dated June 13, 2016 (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q filed on November 8, 2016 [File No. 001-35257])
10.56	Fourth Amendment to Amended and Restated Credit Agreement and Amendment and Restatement Agreement by and between American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP and Bank of America, N.A. dated November 18, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 23, 2016 [File No. 001-35257])

10.57	Purchase Agreement by and between American Midstream Partners, LP, American Midstream Finance Corporation, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and the parties thereto dated December 13, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 16, 2016 [File No. 001-35257])
10.58	Second Amended and Restated Credit Agreement, dated as of March 8, 2017, by and among American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP, Bank of America, N.A., Wells Fargo Bank, National Association Bank of Montreal, Capital One National Association, Citibank, N.A., SunTrust Bank, Natixis New York Branch, ABN AMRO Capital USA, LLC, Barclays Bank PLC, Royal Bank of Canada, Santander Bank N.A., Merrill Lynch ,Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 14, 2017 [File No. 001-35257])
10.59+*	Offer Letter by and between Regina Gregory and American Midstream GP, LLC, dated August 2, 2016
10.60+*	American Midstream GP, LLC Long-Term Incentive Plan Grant of Phantom Units by and between Regina Gregory and American Midstream GP, LLC, dated September 8, 2016.
10.61+*	Unit Purchase Option Grant Notice, by and between American Midstream GP, LLC and Regina Gregory, dated September 19, 2016.
10.62+*	Separation Agreement and Release and Waiver, by and between American Midstream GP, LLC and Michael D. Suder, dated effective November 21, 2016.
10.63+*	Separation Agreement and Release, between Matthew W. Rowland and American Midstream GP, LLC, dated January 17, 2017.
10.64	American Midstream Partners, LP Amended and Restated 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-8 filed on March 9, 2017 [File No.333-216585])
21.1*	American Midstream Partners, LP, List of Subsidiaries
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of Independent Auditors - BDO USA, LLP
23.3*	Consent of Independent Auditors - BDO USA, LLP
23.4*	Consent of Independent Auditors - PricewaterhouseCoopers LLP
23.5*	Consent of Independent Auditors - PricewaterhouseCoopers LLP
23.6*	Consent of Independent Auditors - Deloitte & Touche LLP
23.7*	Consent of Independent Auditors - Ernst & Young LLP

23.8*	Consent of Independent Auditors - Ernst & Young LLP
23.9*	Consent of Independent Auditors - Ernst & Young LLP

23.10*	Consent of Independent Auditors - Ernst & Young LLP
23.11*	Consent of Independent Auditors - BDO USA, LLP
23.12*	Consent of Independent Auditors - BDO USA, LLP
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	2016 and 2015 Pinto Offshore Holdings, LLC Financial Statements
99.2*	2016 and 2015 Delta House FPS, LLC Financial Statements
99.3*	2016 and 2015 Delta House Oil and Gas Lateral, LLC Financial Statements
99.4*	2016 Destin Pipeline Company, L.L.C. Financial Statements
99.5*	2016 Tri-States NGL Pipeline, L.L.C. Financial Statements
99.6*	2016 Okeanos Gas Gathering Company, LLC Financial Statements
99.7*	2016 and 2015 Main Pass Oil Gathering Company, L.L.C. Financial Statements
99.8*	2015 and 2014 Okeanos Gas Gathering Company, LLC Financial Statements
99.9*	2015 and 2014 Destin Pipeline Company, L.L.C. Financial Statements
99.10*	2015 and 2014 Tri-States NGL Pipeline, L.L.C. Financial Statements
99.11*	2014 Delta House Oil and Gas Lateral, LLC Financial Statements
99.12*	2014 Delta House FPS,LLC Financial Statements
99.13*	2014 and 2013 Main Pass Oil Gathering Company Financial Statements
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document

**101.DEF XBRL Taxonomy Extension Definition Linkbase Document

**101.LAB XBRL Taxonomy Extension Label Linkbase Document

**101.PRE XBRL Taxonomy Extension Presentation Linkbase Document
*Filed herewith.

132

+Management contract or compensatory plan arrangement.
**Submitted electronically herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

American Midstream Partners, LP
(Registrant)
By: American Midstream GP, LLC, its general partner

By: /s/ Eric T. Kalamaras

Eric T. Kalamaras
Senior Vice President & Chief Financial Officer
(Principal Financial Officer)

Date: March 27, 2017

Pursuant to the requirements of the Securities Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 27, 2017.

Signatures	Title
/s/ Lynn L. Bourdon III Lynn L. Bourdon III	Chairman of the Board, President and Chief Executive Officer of American Midstream GP, LLC (Principal Executive Officer)
/s/ Eric T. Kalamaras Eric T. Kalamaras	Senior Vice President and Chief Financial Officer of American Midstream GP, LLC (Principal Financial Officer)
/s/ Michael J. Croney Michael J. Croney	Vice President, Chief Accounting Officer and Corporate Controller of American Midstream GP, LLC (Principal Accounting Officer)
/s/ Stephen W. Bergstrom Stephen W. Bergstrom	Director, American Midstream GP, LLC
/s/ John F. Erhard John F. Erhard	Director, American Midstream GP, LLC
/s/ Donald R. Kendall Jr. Donald R. Kendall Jr.	Director, American Midstream GP, LLC
/s/ Daniel R. Revers Daniel R. Revers	Director, American Midstream GP, LLC
/s/ Peter A. Fasullo Peter A. Fasullo	Director, American Midstream GP, LLC
/s/ Joseph W. Sutton Joseph W. Sutton	Director, American Midstream GP, LLC
/s/ Lucius H. Taylor Lucius H. Taylor	Director, American Midstream GP, LLC
/s/ Gerald A. Tywoniuk Gerald A. Tywoniuk	Director, American Midstream GP, LLC

Item 16. Form 10-K Summary

None.

AMERICAN MIDSTREAM PARTNERS, LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Partners of American Midstream Partners, LP

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of changes in partners’ capital and noncontrolling interests and of cash flows present fairly, in all material respects, the financial position of American Midstream Partners, LP and its subsidiaries ("the Partnership") at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because a material weakness in internal control over financial reporting existed as of that date related to the Partnership not maintaining a sufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with its financial reporting requirements. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management’s Annual Report on Internal Control over Financial Reporting appearing under Item 9A. We considered this material weakness in determining the nature, timing and extent of audit tests applied in our audit of the 2016 consolidated financial statements, and our opinion regarding the effectiveness of the Partnership’s internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in management’s report referred to above. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
Houston, Texas
March 24, 2017

American Midstream Partners, LP, and Subsidiaries
Consolidated Balance Sheets
(In thousands, except unit amounts)

	December 31, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$2,939	$—
Accounts receivable, net of allowance for doubtful accounts of $630 in 2016	9,523	3,181
Unbilled revenue	19,799	15,559
Other current assets	16,470	10,459
Total current assets	48,731	29,199
Property, plant and equipment, net	755,457	655,310
Restricted cash	323,564	5,037
Investment in unconsolidated affiliates	291,987	63,704
Intangible assets, net	107,898	112,849
Goodwill	16,262	16,262
Risk management assets	10,401	—
Other assets, net	9,195	9,519
Total assets	$1,563,495	$891,880
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$3,555	$6,389
Accrued gas purchases	7,891	7,281
Accrued expenses and other current liabilities	61,578	23,313
Current portion of debt	4,458	2,338
Total current liabilities	77,482	39,321
Asset retirement obligations	44,363	28,549
Other liabilities	1,488	1,001
3.77% Senior notes	55,979	—
8.50% Senior notes	291,309	—
Revolving credit agreement	711,250	525,100
Deferred tax liabilities	7,858	5,826
Total liabilities	1,189,729	599,797
Commitments and contingencies (see Note 18)		
Convertible preferred units	334,090	169,712
Equity and partners' capital		
General Partner Interest (680 thousand and 536 thousand units issued and outstanding as of December 31, 2016 and December 31, 2015, respectively)	(105,223)	(104,853)
Limited Partner Interests (31,237 thousand and 30,427 thousand units issued and outstanding as of December 31, 2016 and December 31, 2015, respectively)	135,142	188,477
Series B convertible units (1,350 thousand units issued and outstanding as of December 31, 2015)	—	33,593
Accumulated other comprehensive income	(40)	40
Total partners' capital	29,879	117,257
Noncontrolling interests	9,797	5,114
Total equity and partners' capital	39,676	122,371
Total liabilities, equity and partners' capital	$1,563,495	$891,880

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Operations
(In thousands, except per unit amounts)

	Years Ended December 31,		
	2016	2015	2014
Revenues:			
Sales of natural gas, NGLs and condensate	$160,950	$179,818	$255,025
Services	72,572	55,216	52,284
Gains (losses) on commodity derivatives, net	(840)	1,324	1,091
Total revenue	232,682	236,358	308,400
Operating expenses:			
Purchases of natural gas, NGLs and condensate	92,556	105,883	197,952
Direct operating expenses	61,861	60,737	45,919
Corporate expenses	54,223	29,818	24,422
Depreciation, amortization and accretion expense	46,022	38,014	28,832
Loss on sale of assets, net	591	3,011	122
Loss on impairment of property, plant and equipment	697	—	99,892
Loss on impairment of goodwill	—	118,592	—
Total operating expenses	255,950	356,055	397,139
Operating loss	(23,268)	(119,697)	(88,739)
Other income (expense):			
Interest expense	(15,499)	(14,745)	(7,577)
Other expense	—	—	(670)
Earnings in unconsolidated affiliates	40,158	8,201	348
Income (loss) from continuing operations before income taxes	1,391	(126,241)	(96,638)
Income tax expense	(2,057)	(1,134)	(557)
Income (loss) from continuing operations	(666)	(127,375)	(97,195)
Loss from discontinued operations, net of tax	—	(80)	(611)
Net income (loss)	(666)	(127,455)	(97,806)
Net income attributable to noncontrolling interests	2,804	25	214
Net income (loss) attributable to the Partnership	$(3,470)	$(127,480)	$(98,020)
General Partner's interest in net income (loss)	$(48)	$(1,645)	$(1,279)
Limited Partners' interest in net income (loss)	$(3,422)	$(125,835)	$(96,741)
Distribution declared per common unit (1)	$1.71	$1.89	$1.85
Limited Partners' net income (loss) per common unit (See Note 3 and Note 15):			
Basic and diluted:			
Loss from continuing operations	$(1.11)	$(6.00)	$(8.54)
Loss from discontinued operations	—	$—	(0.04)
Net loss	$(1.11)	$(6.00)	$(8.58)
Weighted average number of common units outstanding:			
Basic and diluted	31,043	24,983	13,472

(1) Declared and paid during the years ended December 31, 2016, 2015 and 2014.

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

F-3

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)
(In thousands)

	Years Ended December 31,		
	2016	2015	2014
Net income (loss)	$(666)	$(127,455)	$(97,806)
Unrealized gains (losses) relating to postretirement benefit plan	(80)	38	(102)
Comprehensive income loss	$(746)	$(127,417)	$(97,908)
Less: Comprehensive income attributable to noncontrolling interests	2,804	$25	$214
Comprehensive loss attributable to Partnership	$(3,550)	$(127,442)	$(98,122)

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Changes in Partners' Capital and Noncontrolling Interests
(In thousands)

	General Partner Interest	Limited Partner Interests	Series B Convertible Units	Accumulated Other Comprehensive Income (loss)	Total Partners' Capital	Non controlling Interests
Balances at December 31, 2013	$2,696	$71,039	$ —	$ 104	$73,839	$ 4,628
Net income (loss)	(1,279)	(96,741)	—	—	(98,020)	214
Issuance of common units, net of offering costs	—	351,551	—	—	351,551	—
Issuance of Series B Units	—	—	32,220	—	32,220	
Unitholder contributions	5,678	—	—	—	5,678	—
Unitholder distributions	(2,913)	(39,150)	—	—	(42,063)	—
Issuance and exercise of warrants	(7,164)	7,164	—	—	—	—
Contributions from noncontrolling interest owners	—	21	—	—	21	219
Distributions to noncontrolling interest owners	—	—	—	—	—	(344)
LTIP vesting	(824)	1,067	—	—	243	—
Tax netting repurchases	—	(256)	—	—	(256)	—
Equity compensation expense	1,356	—	—	—	1,356	—
Post-retirement benefit plan	—	—	—	(102)	(102)	—
Balances at December 31, 2014	$(2,450)	$294,695	$ 32,220	$ 2	$324,467	$ 4,717
Net income (loss)	(1,645)	(125,835)	—	—	(127,480)	25
Issuance of common units, net of offering costs	—	82,421	—	—	82,421	—
Issuance of Series B Units	—	—	1,373	—	1,373	—
Unitholder contributions	1,996	—	—	—	1,996	—
Unitholder distributions	(7,023)	(64,714)	—	—	(71,737)	—
Unitholder distributions for Delta House	(96,297)	—	—	—	(96,297)	—
Contributions from noncontrolling interest owners	—	—	—	—	—	739
Distributions to noncontrolling interest owners	—	(20)	—	—	(20)	(367)
LTIP vesting	(2,490)	2,686	—	—	196	—
Tax netting repurchases	—	(756)	—	—	(756)	—
Equity compensation expense	3,056	—	—	—	3,056	—
Post-retirement benefit plan	—	—	—	38	38	—
Balances at December 31, 2015	$(104,853)	$188,477	$ 33,593	$ 40	$117,257	$ 5,114
Net income (loss)	(48)	(3,422)	—	—	(3,470)	2,804
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—
Conversion of Series B Units	—	33,593	(33,593)	—	—	—
Issuance of warrants	4,481	—	—	—	4,481	—
Issuance of common units, net of offering costs	—	2,871	—	—	2,871	—
Unitholder contributions	1,998	—	—	—	1,998	—
Unitholder distributions	(7,938)	(82,700)	—	—	(90,638)	—

Unitholder contribution for Emerald transactions	990	—	—	—	990	—
Contributions from noncontrolling interest owners	—	—	—	—	—	3,366
Distributions to noncontrolling interest owners	—	—	—	—	—	(1,487)
LTIP vesting	(3,487)	3,487	—	—	—	—
Tax netting repurchases	—	(347)	—	—	(347)	—
Equity compensation expense	3,634	—	—	—	3,634	—
Post-retirement benefit plan	—	—	—	(80)	(80)	—
Balances at December 31, 2016	$(105,223)	$135,142	$ —	$ (40)	$29,879	$ 9,797

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Cash Flows
(In thousands)

	Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income (loss)	$(666)	$(127,455)	$(97,806)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion expense	46,022	38,014	28,832
Amortization of deferred financing costs	2,267	1,482	2,212
Amortization of weather derivative premium	966	912	1,035
Unrealized (gain) loss on derivative contracts, net	(10,221)	71	(595)
Non-cash compensation expense	3,634	3,863	1,626
Postretirement benefit plan benefit	(17)	(14)	(45)
Loss on sale of assets, net	591	3,161	207
Loss on impairment of property, plant and equipment	697	—	99,892
Loss on impairment of noncurrent assets held for sale	—	—	673
Loss on impairment of goodwill	—	118,592	—
Earnings in unconsolidated affiliates	(40,158)	(8,201)	(348)
Distributions from unconsolidated affiliates	40,158	8,201	348
Deferred tax expense	2,057	953	213
Allowance for bad debts	630	—	—
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:			
Accounts receivable	(6,972)	1,743	13,067
Unbilled revenue	(4,240)	9,060	2,272
Risk management assets and liabilities	(1,030)	(875)	(809)
Other current assets	(2,817)	(962)	(7,533)
Other assets, net	841	(522)	6,049
Accounts payable	(827)	(1,921)	(12,026)
Accrued gas purchases	610	(7,045)	(5,540)
Accrued expenses and other current liabilities	14,212	1,135	(9,149)
Asset retirement obligations	(858)	(90)	(1,030)
Other liabilities	483	835	(67)
Net cash provided by operating activities	45,362	40,937	21,478
Cash flows from investing activities			
Cost of acquisitions, net of cash acquired and settlements	(2,676)	7,383	(362,316)
Acquisition of investments in unconsolidated affiliates	(150,179)	(65,701)	(12,000)
Additions to property, plant and equipment	(123,078)	(137,029)	(96,998)
Proceeds from disposal of property, plant and equipment	133	4,813	6,323
Distributions from unconsolidated affiliates, return of capital	42,886	12,367	1,632
Restricted cash	(318,527)	6,475	(8,511)
Net cash used in investing activities	(551,441)	(171,692)	(471,870)

Cash flows from financing activities			
Proceeds from issuance of common units, net of offering costs	2,825	82,488	204,255
Unitholder contributions	1,998	1,905	5,588
Unitholder distributions	(64,075)	(53,386)	(28,009)
Issuance of convertible preferred units, net of offering costs	34,413	44,768	—
Issuance of Series B Units	—	—	30,000
Unitholder distributions for common control transactions	—	(96,297)	—
Contributions from noncontrolling interest owners	3,366	584	—
Distributions to noncontrolling interest owners	(1,487)	(114)	(322)
LTIP tax netting unit repurchases	(347)	(756)	(256)
Payment of financing costs	(5,140)	(2,238)	(3,841)
Proceeds from 3.77% Senior Notes	60,000	—	—
Proceeds from 8.50% Senior Notes	294,000	—	—
Payments on other debt	(2,685)	(3,557)	(2,589)
Borrowings on other debt	—	4,709	3,449
Payments on Credit Agreement	(164,950)	(189,150)	(250,870)
Borrowings on Credit Agreement	351,100	341,300	493,085
Net cash provided by financing activities	509,018	130,256	450,490
Net increase (decrease) in cash and cash equivalents	2,939	(499)	98
Cash and cash equivalents			
Beginning of period	—	499	401
End of period	$ 2,939	$ —	$ 499

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

F-7

American Midstream Partners, LP, and Subsidiaries
Notes to Consolidated Financial Statements

1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

General

American Midstream Partners, LP (the “Partnership”, “we”, “us”, or “our”) is a growth-oriented Delaware limited partnership that was formed on August 20, 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. The Partnership’s general partner, American Midstream GP, LLC (the “General Partner”), is 95% owned by High Point Infrastructure Partners, LLC (“HPIP”) and 5% owned by Magnolia Infrastructure Holdings, LLC, both of which are affiliates of ArcLight Capital Partners, LLC ("ArcLight"). Our capital accounts consist of notional General Partner units and units representing limited partner interests.

Nature of business

We provide critical midstream infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. Through our three reportable segments, (i) gathering and processing, (ii) transmission and (iii) terminals, we engage in the business of gathering, treating, processing, and transporting natural gas; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; and storing specialty chemical products.

Our primary assets are strategically located in some of the most prolific onshore and offshore producing regions and key demand markets in the United States. Our gathering and processing assets are primarily located in (i) the Permian Basin of West Texas, (ii) the Cotton Valley/Haynesville Shale of East Texas, (iii) the Eagle Ford Shale of South Texas, (iv) the Bakken Shale of North Dakota, and (v) offshore in the Gulf of Mexico. Our transmission and terminal assets are located in key demand markets in Alabama, Louisiana, Mississippi and Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia.

We own or have ownership interests in more than 3,800 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 15 gathering systems, six interstate pipelines and eight intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 80 MMBbl/d of crude oil and 200 MMcf/d of natural gas; and three marine terminal sites with approximately 2.4 MMBbls of above-ground aggregate storage capacity for petroleum products, distillates, chemicals and agricultural products. A portion of our cash flow is derived from our investments in unconsolidated affiliates.

Basis of presentation

We have prepared the accompanying consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP").

The results of operations for acquisitions accounted for as business combinations have been included in the consolidated financial statements since their respective acquisition dates. See Note 2 - Acquisitions for further information.

Revisions and out of period adjustments

Revenues - Historically, we presented revenue from the sales of natural gas, NGLs and condensate and from the provision of midstream services on an aggregate basis in our consolidated statements of operations. Beginning in 2016, we have broken those amounts into separate line items in our consolidated statements of operations. Our financial statements for prior years have been revised to conform to the new presentation.

Collaborative arrangements - As part of the Costar Midstream, L.L.C. acquisition in October 2014, we acquired a 50% interest in a project to process unstablized condensate and off-spec NGLs. We accounted for this project, which commenced operations during the second quarter of 2016, as an investment in an unconsolidated affiliate under the equity method. During the fourth quarter of 2016, we determined that this accounting method was incorrect and that the project should have been accounted for as a collaborative arrangement. We corrected the cumulative impact of this error with an out of period adjustment in the fourth quarter of 2016, resulting in an increase in services revenue of $1.2 million, offset by an increase in depreciation, amortization and accretion expense of $1.0 million and a reduction in earnings in unconsolidated affiliates of $0.5 million. On a net basis, the correction resulted in a $0.3 million decrease in net income for the fourth quarter of 2016; there was no impact on our results for the year ended December 31, 2016. We also revised our consolidated balance sheet as of December 31, 2015 to correct the related classification errors. Such revision resulted in increases in property, plant and equipment of $7.3 million and intangible assets of $11.9 million, offset by a decrease in investment in unconsolidated affiliates of $18.6 million, and an increase in non-controlling interests of $0.6 million. Finally, we revised our consolidated statement of cash flows for the year ended December 31, 2015 to increase additions to property plant and equipment by $6.5 million, reduce investments in unconsolidated affiliates by $5.9 million and increase non-controlling interests by $0.6 million.

Earnings in unconsolidated affiliates - During the fourth quarter of 2016, we were notified by one of our unconsolidated affiliates that it had identified an error in the financial information it had previously reported to us. Specifically, the affiliate advised that its depreciation expense in prior periods was understated and as a result, its net income for those periods was overstated. As we account for our investment in this affiliate on the equity method, our related earnings were overstated by our pro rata share of this error. We corrected the cumulative impact of this error with an out of period adjustment of $1.4 million to reduce earnings for unconsolidated affiliates in the fourth quarter of 2016. Of this amount, $0.4 million related to 2015 while the remaining $1.0 million related to the first nine months of 2016.

We evaluated the impact of the errors referred to above and concluded that they were not material, individually or in the aggregate, to the financial statements of any previous annual or interim period and that correction of the errors in the fourth quarter of 2016 was not material to the 2016 financial statements.

Transactions between entities under common control

We may enter into transactions with ArcLight affiliates whereby we receive midstream assets or other businesses in exchange for cash or Partnership equity. We account for the net assets acquired at the affiliate's historical cost basis as the transactions are between entities under common control. In certain cases, our historical financial statements will be revised to include the results attributable to the assets acquired from the later of April 15, 2013 (the date Arclight affiliates obtained control of our General Partner) or the date the ArcLight affiliate obtained control of the assets acquired.

Consolidation policy

The accompanying consolidated financial statements include accounts of American Midstream Partners, LP, and its controlled subsidiaries. All significant inter-company accounts and transactions have been eliminated in the preparation of the accompanying consolidated financial statements.

Use of estimates

When preparing consolidated financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and assumptions are based on information available at the time such estimates and assumptions are made. Adjustments made with respect to the use of these estimates and assumptions often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates and assumptions are used in, among other things, i) estimating unbilled revenues, product purchases and operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing long-lived assets, goodwill and intangible assets for possible impairment, iv) estimating the useful lives of assets and v) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Cash, cash equivalents and restricted cash

We consider all highly liquid investments with an original maturity of three months or less at the date of purchase to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

From time to time we are required to maintain cash in separate accounts the use of which is restricted by the terms of our debt agreements or asset retirement obligations. Such amounts are included in Restricted cash in our consolidated balance sheets.

Allowance for doubtful accounts
We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of December 31, 2016, the Partnership recorded allowances for doubtful accounts of $0.6 million.

Derivative financial instruments

Our net income (loss) and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt, commodity prices and fractionation margins (the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). In an effort to manage the risks to unitholders, we use a variety of derivative financial instruments including swaps, collars and interest rate caps to create offsetting positions to specific commodity or interest rate exposures. In accordance with the authoritative accounting guidance, we record all derivative financial instruments in our consolidated balance sheets at fair value as current and long-term assets or liabilities on a net basis by counterparty. We record changes in the fair value of our commodity derivatives in Gains (losses) on commodity derivatives, net while changes in the fair value of our interest rate swaps are included in Interest expense in our consolidated statements of operations.

Our hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by the Board of Directors of our General Partner. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction, and we do not use derivative financial instruments for speculative or trading purposes.

The price assumptions we use to value our derivative financial instruments can affect net income (loss) for each period. We use published market price information where available, or quotations from over-the-counter, market makers to find executable bids and offers. The valuations also reflect the potential impact of conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Fair value measurements

We apply the authoritative accounting provisions for measuring the fair value of our derivative financial instruments and disclosures associated with our outstanding indebtedness. We define fair value as an exit price representing the expected amount we would receive when selling an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We use various assumptions and methods in estimating the fair values of our financial instruments. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximated their fair value due to the short-term maturity of these instruments.

We employ a hierarchy which prioritizes the inputs we use to measure recurring fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1 – Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities;

- Level 2 – Inputs include quoted prices for similar assets and liabilities in active markets that are either directly or indirectly observable; and
- Level 3 – Inputs are unobservable and considered significant to fair value measurement.

We utilize a mid-market pricing convention, or the "market approach," for valuation for assigning fair value to our derivative assets and liabilities. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Property, plant and equipment

We capitalize expenditures related to property, plant and equipment that have a useful life greater than one year. We also capitalize expenditures that improve or extend the useful life of an asset. Maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

We record property, plant, and equipment at cost and recognize depreciation expense on a straight-line basis over the related estimated useful lives of the assets which range from 3 to 40 years. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We record depreciation using the group method of depreciation, which is commonly used by pipelines, utilities and similar assets.

We classify long-lived assets to be disposed of through sales that meet specific criteria as held for sale. We cease depreciating those assets effective on the date the asset is classified as held for sale. We record those assets at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, our estimate of fair value is re-determined when related events or circumstances change.

Impairment of long lived Assets

We evaluate the recoverability of our property, plant and equipment and intangible assets with definite lives when events or circumstances indicate we may not recover the carrying amount of the assets. We continually monitor our operations, the market, and business environment to identify indicators that could suggest an asset or asset group may not be recoverable. We evaluate the asset or asset group for recoverability by estimating the undiscounted future cash flows expected to be derived from their use and disposition. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. An asset or asset group is considered impaired when the estimated undiscounted cash flows are less than the carrying amount. In that event, an impairment loss is recognized to the extent that the carrying amount of the asset or asset group exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of fair values using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations.

Goodwill and intangible assets

We record goodwill for the excess of the cost of an acquisition over the fair value of the net assets of the acquired business. Goodwill is reviewed for impairment at least annually or more frequently if an event or change in circumstance indicates that an impairment may have occurred. We first assess qualitative factors to evaluate whether it is more likely than not that an impairment has occurred and it is therefore necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test indicates that the goodwill is impaired, an impairment loss is recorded.

We record the estimated fair value of acquired customer contracts, relationships and dedicated acreage agreements as intangible assets. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging between 10 years and 30 years. We assess intangible assets for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

Investment in unconsolidated affiliates

We hold membership interests in entities that own and operate natural gas pipeline systems and NGL and crude oil pipelines in and around Louisiana, Alabama, Mississippi and the Gulf of Mexico. While we have significant influence over these entities, we do not control them and therefore, they are accounted for using the equity method and are reported in Investment in unconsolidated affiliates in the consolidated balance sheets. We evaluate the recoverability of these investments on a regular basis and recognize impairment write downs if we determine a loss in value represents an other than temporary decline.

Deferred financing costs

Costs incurred in connection with our Credit Agreement are deferred and charged to interest expense over the term of the related credit arrangement. Such amounts are included in Other assets, net in our consolidated balance sheet. Costs incurred in connection with our 8.50% Senior Notes and 3.77% Senior Notes are also deferred and charged to interest expense over the respective term of the agreements; however, these amounts are reflected as a reduction of the related obligation. Gains or losses on debt repurchases or extinguishment include any associated unamortized deferred financing costs.

Asset retirement obligations

Asset retirement obligations ("ARO") are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and operation. An ARO is initially measured at its estimated fair value. Upon initial recognition, we also record an increase to the carrying amount of the related long-lived asset. We depreciate the asset using the straight-line method over the period during which it is expected to provide benefits. After initial recognition, we revise the ARO to reflect the passage of time and for changes in the estimated amount or timing of cash flows.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for certain of our offshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's experience, or the asset's estimated economic life. The useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

Commitments, contingencies and environmental liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur from the remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulation taking into consideration the likely effects of inflation and other factors. These amounts also take into account our prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual cost or new information. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

Noncontrolling interests

Noncontrolling interests represent the minority interest holders' proportionate share of the equity in certain of our consolidated subsidiaries and are adjusted for the minority interest holders' proportionate share of the subsidiaries' earnings or losses each period.

Revenue recognition

We recognize revenue from the sale of commodities (e.g., natural gas, crude oil, NGLs or condensate) as well as from the provision of gathering, processing, transportation or storage services when all of the following criteria are met: i) persuasive evidence of an exchange arrangement exists, ii) delivery has occurred or services have been rendered, iii) the price is fixed or determinable, and iv) collectability is reasonably assured. We recognize revenue from the sale of commodities and the related cost of product sold on a gross basis for those transactions where we act as the principal and take title to commodities that are purchased for resale.

Purchases of natural gas, NGLs and condensate

Purchases of natural gas, NGLs and condensate represent the cost of commodities purchased for resale or obtained in connection with certain of our customer revenue arrangements. These costs do not include an allocation of depreciation expense or direct operating costs.

Corporate expenses

Corporate expenses include compensation costs for executives and administrative personnel, professional service fees, rent expense and other general and administrative expenses and are recognized as incurred.

Operational balancing agreements and natural gas imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a natural gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in-kind through future receipt or delivery of natural gas. Natural gas imbalances are recorded in Other current assets or Accrued expenses and other current liabilities on our consolidated balance sheets at cost which approximates fair value.

Equity-based compensation

We award equity-based compensation to management, non-management employees and directors under our Long-Term Incentive Plan ("LTIP"), which provides for the issuance of options, unit appreciation rights, restricted units, phantom units, other unit-based awards, unit awards or replacement awards, as well as tandem Distribution Equivalent Rights ("DERs"). Compensation expense is measured by the fair value of the award at the date of grant as determined by management. Compensation expense is recognized in Corporate expenses and Direct operating expenses over the requisite service period of each award.

Income taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income are generally borne by our unitholders through the allocation of taxable income. American Midstream Blackwater, LLC, a subsidiary of the Partnership, owns a subsidiary that has operations which are subject to both federal and state income taxes. We account for income taxes of that subsidiary using an asset and liability approach for financial accounting and reporting of income taxes. If it is more than likely that a deferred tax asset will not be realized, a valuation allowance is recognized.

Margin tax expense results from the enactment of laws by the State of Texas that apply to entities organized as partnerships and is included in Income tax expense in our consolidated statements of operations. The Texas margin tax is computed on the portion of our taxable margin which is apportioned to Texas.

Net income (loss) for financial statement purposes may differ significantly from taxable income (loss) allocable to unitholders as a result of differences between the financial reporting and income tax bases of our assets and liabilities and the taxable income allocation requirement under our Partnership Agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in us is not available.

Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) is comprised solely of adjustments related to the Partnership's postretirement benefit plan.

Limited partners' net income (loss) per unit

We compute earnings per unit using the two-class method. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the Partnership Agreement, regardless of whether the General Partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the General Partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The two-class method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the General Partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit.

New Accounting Pronouncements

Recently Adopted Accounting Standards

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. This update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, including interim periods therein, and is applied retrospectively. Early adoption is permitted for financial statements that have not been previously issued. ASU 2015-15, Presentation and Subsequent Measurement of Debt Issue Costs Associated with Line of Credit Arrangements, was subsequently issued to address the absence of authoritative guidance for debt issuance costs related to line-of-credit arrangements and states that the Securities and Exchange Commission ("SEC") staff will not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement.
The Partnership adopted the requirements of ASU No. 2015-03 effective January 1, 2016 and classifies the debt issuance costs applicable to its 8.50% Senior Notes and 3.77% Senior Notes as a reduction of the related debt obligation. Additionally, the Partnership continues to classify the debt issuance costs relating to its Credit Agreement within Other assets, net as allowed by ASU No. 2015-15.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805). This update requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been issued. The Partnership adopted the updated guidance effective January 1, 2016 without impact to its financial statements.

Accounting Standards Issued Not Yet Adopted

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), which amends the existing accounting guidance for revenue recognition. The update requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU No. 2015-14 was subsequently issued and deferred the effective date to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that period. In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal Versus Agent Considerations, as further clarification on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing as further clarification on identifying performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, as clarifying guidance on specific narrow scope improvements and practical expedients. We are in the process of reviewing our various customer arrangements in order to determine the impact that these updates will have on our consolidated financial statements and related disclosures. We have engaged a third-party consultant to assist with our review, which we currently expect to complete in the third quarter of 2017.

In February 2016, the FASB issued ASU No. 2016-02 (Topic 842) "Leases" which supersedes the lease recognition requirements in Accounting Standards Codification Topic 840, "Leases". Under ASU No. 2016-02 lessees are required to recognize assets and liabilities on the balance sheet for most leases and provide enhanced disclosures. Leases will continue to be classified as either finance or operating. ASU No. 2016-02 is effective for annual reporting periods, and interim periods within those years beginning after December 15, 2018. Entities are required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements, and there are certain optional practical expedients that an entity may elect to apply. Full retrospective application is prohibited and early adoption by public entities is permitted. Based upon our evaluation to date, we anticipate that the adoption of ASU 2016-02 will have a material effect on our consolidated financial statements as we will be required to reflect our various lease obligations and associated asset use rights on our consolidated balance sheets. The adoption may also impact our debt covenant compliance and may require us to modify or replace certain of our existing information systems. We have not yet determined the timing or manner in which we will implement the updated guidance.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 320): Classification of Cash Receipts and Cash Payments, which addresses eight specific cash flow issues with the objective of reducing the existing diversity of presentation and classification in the statement of cash flows. ASU No. 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal periods. Early adoption is permitted, but only if all aspects are adopted in the same period. The Partnership is currently evaluating the impact this update will have on its consolidated statements of cash flows and related disclosures.

In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash, which aims to improve the disclosure of the change during the period in total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash or restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statement of cash flows. The update is effective beginning first quarter of 2018. Early adoption is permitted, but it must occur in the first interim period. Any adjustments required in early adoption of this update should be reflected as of the beginning of the fiscal year that includes the interim period and should be applied using a retrospective transition method to each period. The Partnership is evaluating the impact that this update will have on our consolidated statement of cash flows and related disclosures.

2. Acquisitions and Divestitures

JP Energy Partners

On March 8, 2017, the Partnership completed the acquisition of JPE, an entity controlled by ArcLight affiliates, in a unit-for-unit merger. In connection with the transaction, each JPE common or subordinated unit held by investors not affiliated with ArcLight was converted into the right to receive 0.5775 of a Partnership common unit, and each JPE common or subordinated unit held by ArcLight affiliates was converted into the right to receive 0.5225 of a Partnership common unit. The Partnership issued a total of 20.2 million of its common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates.

As both the Partnership and JPE were controlled by ArcLight affiliates, the acquisition represents a transaction among entities under common control and will be accounted for as a common control transaction. Although the Partnership is the legal acquirer, JPE is considered to be the acquirer for accounting purposes as ArcLight obtained control of JPE prior to obtaining control of the Partnership on April 15, 2013. As a result, JPE will record the acquisition of the Partnership at ArcLight’s historical cost basis. The Partnership will file recast historical cost financial statements for the combined entity in May 2017.

JPE owns, operates and develops a diversified portfolio of midstream energy assets with three business segments (i) crude oil pipelines and storage, (ii) refined products terminals and storage and (iii) NGL distribution and sales, which together provide midstream infrastructure solutions for the growing supply of crude oil, refined products and NGLs, in the United States.

Delta House Investment

On September 18, 2015, the Partnership acquired a 26.3% interest in Pinto Offshore Holdings, LLC ("Pinto"), an entity that owns 49% of the Class A Units of Delta House FPS LLC and of Delta House Oil and Gas Lateral LLC (collectively referred to herein as "Delta House"), a floating production system platform with associated crude oil and gas export pipelines, located in the Mississippi Canyon region of the deepwater Gulf of Mexico ("Delta House").

We acquired our 26.3% non-operated interest in Pinto in exchange for $162.0 million in cash, funded by the proceeds of a public offering of 7.5 million of the Partnership's common units and with borrowings under the Partnership’s Amended and Restated Credit Agreement (the "Credit Agreement"). As a result, we own a minority interest in Pinto, which represents an indirect interest in 12.9% of Delta House's Class A Units. Pursuant to the Pinto LLC Agreement, we have no management control or authority over the day-to-day operations. Our interest in Pinto is accounted for as an equity method investment in the consolidated financial statements.

Because our interest in Delta House was previously owned by an ArcLight affiliate, we accounted for our investment at the affiliate's historical cost basis of $65.7 million and was recorded in Investments in unconsolidated affiliates in our consolidated balance sheets and as an investing activity within the related consolidated statement of cash flows. The amount by which the total consideration exceeded affiliate's historical cost basis was $96.3 million and is recorded as a distribution within the consolidated statements of changes in partners’ capital and noncontrolling interests and a financing activity in the consolidated statement of cash flows.

On April 25, 2016, the Partnership increased its investment in Delta House through the purchase of 100% of the outstanding membership interests in D-Day Offshore Holdings, LLC (“D-Day”), an Arclight affiliate which owned 1.0% of Delta House Class A Units in exchange for approximately $9.9 million in cash funded with borrowings under the Partnership’s Credit Agreement.

Because the additional investment in Delta House was previously owned by an ArcLight affiliate, we recorded our investment in D-Day at the affiliate's historical cost basis of $9.9 million in Investments in unconsolidated affiliates on our consolidated balance sheet and as an investing activity within our condensed consolidated statements of cash flows.

On October 31, 2016, D-Day acquired an additional 6.2% direct interest in Delta House Class A Units from unrelated parties for approximately $48.8 million which was funded with $34.5 million in net proceeds from the issuance of 2,333,333 Series D convertible preferred units ("Series D Preferred Units") to an ArcLight affiliate, plus $14.3 million in cash funded with borrowings under our Credit Agreement.

Our investments in D-Day and Pinto result in the Partnership holding a 20.1% non-operated direct and indirect interests in the Class A units of Delta House as of December 31, 2016. The Partnership's interest in Delta House consists of a 20.1% interest in Class A Units of Delta House FPS, which are currently entitled to receive 100% of the distributions from Delta House FPS until a certain payout threshold is met. Once the payout threshold is met, approximately 7% of distributions from Delta House FPS will be paid to the Class B membership interests in Delta House FPS.

Emerald Transactions

On April 25, 2016 and April 27, 2016, American Midstream Emerald, LLC ("Emerald"), a wholly-owned subsidiary of the Partnership, entered into two purchase and sale agreements with Emerald Midstream, LLC, an ArcLight affiliate, for the purchase of membership interests in certain midstream entities.

On April 25, 2016, Emerald entered into the first purchase and sale agreement for the purchase of membership interests in entities that own and operate natural gas pipeline systems and NGL pipelines in and around Louisiana, Alabama, Mississippi, and the Gulf of Mexico (the "Pipeline Purchase Agreement"). Pursuant to the Pipeline Purchase Agreement, Emerald acquired (i) 49.7% of the issued and outstanding membership interests of in Destin Pipeline Company, L.L.C. ("Destin"), (ii) 16.7% of the issued and outstanding membership interests of Tri-States NGL Pipeline, L.L.C. ("Tri-States"), and (iii) 25.3% of the issued and outstanding membership interests of Wilprise Pipeline Company, L.L.C. ("Wilprise"), in exchange for approximately $183.6 million (the "Pipeline Transaction").

The Destin pipeline is a FERC-regulated, 255-mile natural gas transportation system with total capacity of 1.2 Bcf/d. The system originates offshore in the Gulf of Mexico and includes connections with four producing platforms and six producer-operated laterals, including Delta House. The 120-mile offshore portion of the Destin system terminates at the Pascagoula processing plant, which is owned by Enterprise Products Partners, LP, and is the single source of raw natural gas to the plant. The onshore portion of Destin is the sole delivery point for merchant-quality gas from the Pascagoula processing plant and extends 135 miles north in Mississippi. Destin currently serves as the primary transfer of gas flows from the Barnett and Haynesville shale plays to Florida markets through interconnections with major interstate pipelines. Contracted volumes on the Destin pipeline are based on life-of-field dedications, dedicated volumes over a given period, or interruptible volumes as capacity permits. We became the operator of the Destin pipeline on November 1, 2016. The Tri-States pipeline is a FERC-regulated, 161-mile NGL pipeline and sole form of transport to Louisiana-based fractionators for NGLs produced at the Pascagoula plant served by Destin and other facilities. The Wilprise pipeline is a FERC-regulated, approximately 30-mile NGL pipeline that originates at the Kenner Junction and terminates in Sorrento, Louisiana, where volumes flow via pipeline to a Baton Rouge fractionator.

On April 27, 2016, Emerald entered into a second purchase and sale agreement for the purchase of 66.7% of the issued and outstanding membership interests of Okeanos Gas Gathering Company, LLC ("Okeanos"), in exchange for a cash purchase price of approximately $27.4 million (such Purchase and Sale Agreement, the "Okeanos Purchase

Agreement," and such transaction, the "Okeanos Transaction," and together with the Pipeline Transaction, the "Emerald Transactions"). The Okeanos pipeline is a 100-mile natural gas gathering system located in the Gulf of Mexico with a total capacity of 1.0 Bcf/d. The Okeanos pipeline connects two platforms and one lateral, terminating at the Destin Main Pass 260 platform in the Mississippi Canyon region of the Gulf of Mexico. Contracted volumes on the Okeanos pipeline are based on life-of-field dedication. We became the operator of the Okeanos pipeline on November 1, 2016.

The Partnership funded the aggregate purchase price for the Emerald Transactions with the issuance of 8,571,429 Series C convertible preferred units (the "Series C Units") representing limited partnership interests in the Partnership and a warrant (the " Series C Warrant") to purchase up to 800,000 common units representing limited partnership interests in the Partnership ("common units") at an exercise price of $7.25 per common unit amounting to a combined value of approximately $120.0 million, plus additional borrowings of $91.0 million under our Credit Agreement. ArcLight affiliates hold and participate in distributions on our Series C Units with such distributions being made in paid-in-kind Series C Units, cash or a combination thereof at the election of the Board of Directors of our General Partner.

Because our interests in the entities underlying the Emerald Transactions were previously owned by an ArcLight affiliate, we accounted for our investments at the affiliate's historical cost basis of $212.0 million, and recorded them in Investment in unconsolidated affiliates in our consolidated balance sheet, and as an investing activity of $100.9 million within the consolidated statement of cash flows. The amount by which the affiliate's historical basis exceeded total consideration paid was $1.0 million and is recorded as a contribution from our General Partner in the consolidated statement of changes in partners' capital and noncontrolling interests.

Gulf of Mexico Pipeline

On April 15, 2016, American Panther LLC, ("American Panther"), a 60%-owned subsidiary of the Partnership, acquired approximately 200 miles of crude oil, natural gas, and salt water onshore and offshore Gulf of Mexico pipelines ("Gulf of Mexico Pipeline") from Chevron Pipeline Company and Chevron Midstream Pipeline, LLC for approximately $2.7 million in cash and the assumption of certain asset retirement obligations. The Partnership controls American Panther and therefore consolidates it for financial reporting purposes.

The American Panther acquisition was accounted for using the acquisition method of accounting and as a result, the purchase price was allocated to the assets acquired and liabilities assumed based on their respective estimated fair values as of the acquisition date. The purchase price allocation included $16.6 million in pipelines, $0.4 million in land, $14.3 million in asset retirement obligations, and $1.8 million in noncontrolling interests.

American Panther contributed revenue of $13.2 million and operating income of $7.4 million to the Partnership for the year ended December 31, 2016. Such amounts are included in the Partnership's Gathering and Processing segment. During the year ended December 31, 2016, the Partnership incurred $0.3 million of transaction costs related to the American Panther acquisition which are included in Corporate expenses in our consolidated statements of operations for the periods.
Unaudited pro forma financial information depicting what the Partnership's revenue, net income and per unit amounts would have been had the American Panther acquisition occurred on January 1, 2016, is not available because Chevron Pipeline Company and Chevron Midstream Pipeline, LLC did not historically operate the acquired assets as a standalone business.

Costar Acquisition

On October 14, 2014, the Partnership acquired 100% of the membership interests of Costar Midstream, L.L.C. ("Costar") from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC, in exchange for cash and common units with an aggregate value of $405.3 million. Costar is an onshore gathering and processing company with its primary gathering, processing, fractionation, and off-spec condensate treating and stabilization assets in East Texas and the Permian basin, with a significant crude oil gathering system project in the Bakken oil play.

The Costar acquisition was accounted for using the acquisition method of accounting and as a result, the purchase price was allocated to the assets acquired and liabilities assumed based on their respective fair values as of the acquisition date. The excess of the aggregate purchase price of the fair values of the assets acquired, liabilities assumed and the noncontrolling interest was classified as goodwill, which was attributable to future prospective customer agreements expected to be obtained as a result of the acquisition. The operating systems acquired have been included in the Partnership's Gathering and Processing segment from the acquisition date.

During 2015, the Partnership reached agreements with the Costar sellers regarding certain matters which resulted in a return of $7.4 million of cash to the Partnership and related reductions in the goodwill initially recorded. Additionally, in February 2016, the Partnership reached a settlement of certain indemnification claims with the Costar sellers whereby 1,034,483 common units held in escrow with a fair value of $6.8 million were returned to the Partnership, while the Partnership agreed to pay the Costar sellers an additional $0.3 million. The net impact of this settlement was recorded as a reduction in property, plant and equipment in the first quarter of 2016. The Partnership recognized a $95.0 million impairment of the remaining Costar goodwill in fourth quarter of 2015.

Lavaca Acquisition

On January 31, 2014, the Partnership acquired approximately 120 miles of high- and low-pressure pipelines and associated facilities located in the Eagle Ford shale in Gonzales and Lavaca Counties, Texas from Penn Virginia Corporation (NYSE: PVA) ("PVA") for $104.4 million in cash. The Lavaca acquisition was financed with proceeds from the Partnership's January 2014 equity offering and from the issuance of Series B Units to our General Partner.

The Lavaca acquisition was accounted for using the acquisition method of accounting and, as a result, the purchase price was allocated to the assets acquired upon their respective fair values as of the acquisition date. The excess of the purchase price over the fair value of the assets acquired was classified as goodwill, which was attributable to future prospective customer agreements expected to be obtained as a result of the acquisition. The operating systems acquired have been included in the Partnership's Gathering and Processing segment from the acquisition date. The Partnership recognized a $23.6 million impairment of the remaining Lavaca goodwill in the fourth quarter of 2015.

3. Discontinued Operations

On December 17, 2013, the Partnership acquired Blackwater Midstream Holdings LLC ("Blackwater") from an ArcLight affiliate. As part of the Blackwater acquisition, we acquired certain long-lived terminal assets which were immediately classified as held for sale. Due to deteriorating market conditions, the Partnership recognized an impairment charge on these assets of $0.7 million in 2014. These assets were sold during the third quarter of 2015 at a nominal loss.

We classified these assets as discontinued operations within our consolidated statements of operations, but elected not to separately present the related operating, investing and financing cash flows in our consolidated statements of cash flows as the related activity was immaterial for all periods presented.

The following table presents the revenue, expense and (loss) gain from discontinued operations associated with the assets classified as held for sale for the years ended December 31, 2015 and 2014 (in thousands, except per unit amounts):

	Years Ended December 31,	
	2015	2014
Revenue	$74	$474
Expense	(196)	(658)
Impairment	—	(673)
Loss on sale of assets	(150)	(87)
Income tax benefit	192	333
Loss from discontinued operations, net of tax	$(80)	$(611)
Limited partners' net income (loss) per unit from discontinued operations (basic and diluted)	$—	$(0.04)

4. Concentration of Credit Risk and Trade Accounts Receivable

Our primary assets, which are strategically located in Alabama, Georgia, Louisiana, Mississippi, North Dakota, Tennessee, Texas and the Gulf of Mexico, provide critical infrastructure that links customers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. As a result of recent acquisitions and geographic diversification, we have reduced the concentration our of trade receivable balances. Our customers' historical financial and operating information is analyzed prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. We record allowances for potentially uncollectible accounts receivable when necessary. For the year ended December 31, 2016, we recorded an allowance of $0.6 million.

Significant customers are defined as those who represent 10% of more of our consolidated revenue during the year. In 2016, we had one such customer who accounted for 10% of our consolidated revenue. In 2015, we had one such customer who accounted for 10% of our consolidated revenue. In 2014, we had three such customers who accounted for 22%, 12% and 10%, respectively, of our consolidated revenue.

5. Other Current Assets

Other current assets consists of the following (in thousands):

	December 31,	
	2016	2015
Prepaid insurance	$4,308	$3,948
Other receivables	2,376	1,573
Due from related parties	4,206	64
Risk management assets	429	365
Other prepaids	2,967	2,866
Miscellaneous	2,184	1,643
	$16,470	$10,459

6. Risk Management Activities

Commodity Derivatives

To limit the effect of commodity price changes and maintain our cash flow and the economics of our development plans, we enter into commodity derivative contracts from time to time. The terms of the contracts depend on various factors, including management's view of future commodity prices, economics on purchased assets and future financial commitments. This hedging program is designed to mitigate the effect of commodity price declines while allowing us to participate in some commodity price increases. Management regularly monitors the commodity markets and financial commitments to determine if, when, and at what level commodity hedging is appropriate in accordance with policies that are established by the board of directors of our General Partner.

We enter into commodity contracts with multiple counterparties, and in some cases, may be required to post collateral with our counterparties in connection with our derivative positions. The counterparties are not required to post collateral with us in connection with their derivative positions. Netting agreements are in place that permit us to offset our commodity derivative asset and liability positions with our counterparties.

As of December 31, 2016 and 2015, we did not have any outstanding commodity derivative contracts.

Interest Rate Swaps

To manage the impact of the interest rate risk associated with our Credit Agreement, we enter into interest rate swaps from time to time, effectively converting a portion of the cash flows related to our long-term variable rate debt into fixed rate cash flows.

As of December 31, 2016, our outstanding interest rate swap contracts consist of the following (in thousands):

Notional Amount	Term	Fair Value
$200,000	January 3, 2017 thru September 3, 2019	$1,912
$100,000	January 1, 2018 thru December 31, 2021	$3,090
$150,000	January 1, 2018 thru December 31, 2022	$5,219
		$10,221

The fair value of our interest rate swaps was estimated using a valuation methodology based upon forward interest rate and volatility curves as well as other relevant economic measures, if necessary. Discount factors may be utilized to extrapolate a forecast of future cash flows associated with long dated transactions or illiquid market points. The inputs, which represent Level 2 inputs in the valuation hierarchy, are obtained from independent pricing services and we have made no adjustments to those prices.

Weather Derivative

In the second quarters of 2016 and 2015, we entered into weather derivatives to mitigate the impact of potential unfavorable weather to our operations under which we could receive payments totaling up to $30.0 million in the event that a hurricane or hurricanes of certain strength pass through the area as identified in the related agreement. The weather derivatives, which are accounted for using the intrinsic value method, were entered into with a single counterparty and we were not required to post collateral.

We paid premiums of $1.0 million and $0.9 million in 2016 and 2015, respectively, which are amortized to Direct operating expenses on a straight-line basis over the 1 year term of the contract. Unamortized amounts associated with weather derivatives were approximately $0.4 million at December 31, 2016 and 2015, and are included in Other current assets on the consolidated balance sheets.

Our interest rate swaps and weather derivatives were recorded in our consolidated balance sheets, under the following captions (in thousands):

Balance Sheet Classification	Gross Risk Management Position		Netting Adjustment		Net Risk Management Position	
	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015
Other current assets	$487	$ 365	$ (58)	$ —	$429	$ 365
Risk management assets	10,401	—	—	—	10,401	—
Total assets	$10,888	$ 365	$ (58)	$ —	$10,830	$ 365
Accrued expenses and other liabilities	$(238)	$ —	$ 58	$ —	$(180)	$ —
Total liabilities	$(238)	$ —	$ 58	$ —	$(180)	$ —

For the years ended December 31, 2016, 2015 and 2014, the realized and unrealized gains (losses) associated with our commodity, interest rate and weather derivative instruments were recorded in our consolidated statements of operations, under the captions as follows (in thousands):

	Realized	Unrealized
2016		
Gains (losses) on commodity derivatives, net	$(840)	$—
Interest expense	—	10,221
Direct operating expenses	(966)	—
Total	$(1,806)	$10,221
2015		
Gains (losses) on commodity derivatives, net	$1,610	$(286)
Interest expense	(240)	215
Direct operating expenses	(913)	—
Total	$457	$(71)
2014		
Gains (losses) on commodity derivatives, net	$735	$356
Interest expense	(433)	239
Direct operating expenses	(1,035)	—
Total	$(733)	$595

7. Property, Plant and Equipment, Net

Property, plant and equipment, net. consists of the following (in thousands):

	Useful Life (in years)	December 31, 2016	December 31, 2015
Land	N/A	$ 15,112	$ 10,319
Construction in progress	N/A	122,884	45,383
Buildings and improvements	4 to 40	12,413	10,871
Processing and treating plants	8 to 40	134,434	115,568
Pipelines and compressors	3 to 40	554,965	538,402
Storage	20 to 40	58,786	58,220
Equipment	5 to 20	39,470	22,510
Total property, plant and equipment		938,064	801,273
Less accumulated depreciation		(182,607)	(145,963)
Property, plant and equipment, net		$ 755,457	$ 655,310

At December 31, 2016 and 2015, gross property, plant and equipment included $231.1 million and $160.4 million, respectively, related to our FERC regulated interstate and intrastate assets.

Depreciation expense totaled $38.3 million, $31.9 million and $23.9 million for the years ended December 31, 2016, 2015 and 2014, respectively. Capitalized interest was $2.7 million, $1.9 million and $0.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil led to a corresponding decrease in natural gas and crude oil production impacting the volume of natural gas and NGLs we gather and process on certain assets. As a result, an asset impairment charge of $99.9 million was recorded to reduce the carrying value of the impacted assets to their estimated fair value. The related fair value measurements were based on significant inputs not observable in the market and thus represented Level 3 measurements as defined by ASC 820. Primarily using the income approach, the fair value estimates were based on i) present value of estimated EBITDA, ii) an assumed discount rate of 9.5%, and iii) the expected remaining useful life of the asset or asset group.

8. Goodwill and Intangible Assets, Net

Management performs an annual goodwill assessment at the reporting unit level. We first assess qualitative factors to evaluate whether it is more likely than not that an impairment has occurred and if it is then necessary to perform the two-step goodwill impairment test. The two-step goodwill impairment test involves fair value measurements that are based on significant inputs not observable in the market and thus represent Level 3 measurements as defined by ASC 820. In the two-step assessment, management primarily uses a discounted cash flow analysis, supplemented by a market approach analysis. Key assumptions in the discounted cash flow analysis include an appropriate discount rate, estimated volumes, storage utilization, terminal year multiples, operating costs and maintenance capital expenditures. In estimating cash flows, management incorporates current market information, as well as historical and other factors into the forecasted commodity prices and contracted rates used.

In 2015, management utilized the approach described above in performing the first step of its annual goodwill impairment test. As a result of our step one analysis, we determined that the estimated fair value of certain reporting units within our Gathering and Processing reportable segment were less than their respective carrying amounts, primarily due to changes in assumptions related to commodity prices, timing of estimated drilling by producers, and discount rates. These assumptions were adversely impacted by the continuing decline in market conditions within the energy sector.

The second step of the goodwill impairment test involved allocating the estimated fair value of each reporting unit among the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The results of the hypothetical purchase price allocation indicated there was no fair value attributable to goodwill of the reporting units within our Gathering and Processing reportable segment. As a result, we recognized a goodwill impairment charge of $118.6 million during the fourth quarter which
consisted of $95.0 million and $23.6 million related to the Costar and Lavaca acquisitions, respectively.

At December 31, 2016 and 2015, our goodwill relates to the Blackwater reporting unit within our Terminals segment. During the fourth quarter of 2016, we assessed qualitative factors to evaluate whether it was more likely than not that a related goodwill impairment had occurred. Based on that assessment, which considered the amount by which the fair value of the Blackwater reporting unit exceeded its related carrying value at the time of the last annual impairment test coupled with the continued performance of that reporting unit, we concluded that the goodwill was not impaired and that completion of the two-step impairment test was not necessary.

Intangible assets, net, consists of customer relationships, dedicated acreage agreements, and collaborative arrangements identified as part of the Costar, Lavaca and Blackwater acquisitions. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging from approximately 10 years to 30 years. Intangible assets, net, consist of the following (in thousands):

	December 31,	
	2016	2015
Gross carrying amount:		
Customer relationships	$53,400	$53,400
Dedicated acreage	53,350	53,350
Collaborative arrangements	11,884	11,884
	$118,634	$118,634
Accumulated amortization:		
Customer relationships	$(5,696)	$(3,124)
Dedicated acreage	(4,439)	(2,661)
Collaborative arrangements	(601)	—
	$(10,736)	$(5,785)
Net carrying amount:		
Customer relationships	$47,704	$50,276
Dedicated acreage	48,911	50,689
Collaborative arrangements	11,283	11,884
	$107,898	$112,849

For the years ended December 31, 2016, 2015 and 2014, amortization expense on our intangible assets totaled $4.6 million, $5.3 million and $4.1 million, respectively. Estimated amortization expense for each of the next five fiscal years (2017 – 2021) is approximately $4.6 million per year and $85.0 million thereafter.

9. Investment in Unconsolidated Affiliates

The following table presents activity in the Partnership's investments in unconsolidated affiliates (in thousands):

	Delta House [1]		Emerald Transactions					
	FPS	OGL	Destin	Tri-States	Okeanos	Wilprise	MPOG	Total
Ownership % at December 31, 2016	20.1 %	20.1 %	49.7 %	16.7 %	66.7 %	25.3 %	66.7 %	
Balance at December 31, 2013	$—	$—	$—	$—	$—	$—	$—	$—
Investment	—	—	—	—	—	—	12,000	12,000
Earnings in unconsolidated affiliates	—	—	—	—	—	—	348	348
Contributions	—	—	—	—	—	—	—	—
Distributions	—	—	—	—	—	—	(1,980)	(1,980)
Balance at December 31, 2014	—	—	—	—	—	—	10,368	10,368
Investment	40,559	25,144	—	—	—	—	—	65,703
Earnings in unconsolidated affiliates	5,457	2,013	—	—	—	—	731	8,201
Contributions	—	—	—	—	—	—	—	—
Distributions	(12,551)	(4,097)	—	—	—	—	(3,920)	(20,568)
Balance at December 31, 2015	33,465	23,060	—	—	—	—	7,179	63,704
Investment	55,461	3,255	122,830	56,681	27,451	5,064	—	270,742
Earnings in unconsolidated affiliates	21,022	9,260	3,946	1,633	3,642	437	218	40,158
Contributions	—	—	—	—	—	—	430	430
Distributions	(45,465)	(10,125)	(15,894)	(3,292)	(4,034)	(557)	(3,679)	(83,046)
Balance at December 31, 2016	$64,483	$25,450	$110,882	$55,022	$27,059	$4,944	$4,148	$291,988

(1) Represents direct and indirect ownership interests in Class A Units.

We have included the audited financial statements for each of the unconsolidated affiliates listed above, except Wilprise, as exhibits to this Form 10-K. As of December 31, 2016, Wilprise had current assets of $1.6 million, non-current assets (primarily property, plant and equipment) of $12.0 million, liabilities of $0.3 million, and members' equity of $13.3 million. Additionally, for the year ended December 31, 2016, Wilprise had revenues of $5.1 million, operating expenses of $1.9 million, and net income of $3.2 million.

Our investments in the unconsolidated affiliates underlying the Emerald Transactions were acquired in late April 2016. The following table presents information for each of these affiliates for the portion of 2016 that we held the related investments:

	Emerald Transactions			
	Destin	Tri-States	Okeanos	Wilprise
Revenues	34,360	25,557	10,453	3,306
Net income	8,272	15,983	1,911	2,028
Partnership ownership %	49.7 %	16.7 %	66.7 %	25.3 %

Partnership share of investee net income	4,109	2,664	1,274	513
Basis difference amortization	(163)	(1,031)	2,368	(76)
Earnings in unconsolidated affiliates	3,946	1,633	3,642	437

The unconsolidated affiliates were determined to be variable interest entities due to disproportionate economic interests and decision making rights. In each case, the Partnership lacks the power to direct the activities that most significantly impact the unconsolidated affiliate's economic performance. As the Partnership does not hold a controlling financial interest in these affiliates, the Partnership accounts for its related investments using the equity method. Additionally, the Partnership's maximum exposure to loss related to each entity is limited to its equity investment as presented on the consolidated balance sheet, as it is not obligated to absorb losses greater than its proportional ownership percentages indicated above. The Partnership's right to receive residual returns is not limited to any amount less than the ownership percentages indicated above.

10. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consists of the following (in thousands):

	December 31,	
	2016	2015
Capital expenditures	$13,319	$3,984
Convertible preferred unit distributions	7,103	—
Current portion of asset retirement obligations	6,499	6,822
Accrued interest	5,743	1,411
Additional Blackwater acquisition consideration	5,000	—
Employee compensation	4,226	3,114
Due to related parties	3,895	3,894
Transaction costs	3,000	—
Deferred financing costs	2,743	—
Gas imbalances payable	1,098	413
Other	8,952	3,675
	$61,578	$23,313

11. Asset Retirement Obligations

The following table presents activity in the Partnership's asset retirement obligations (in thousands):

	Years Ended December 31,	
	2016	2015
Beginning balance	$35,371	$34,645
Liabilities assumed (1)	14,542	—
Revision in estimate	230	—
Expenditures	(858)	(91)
Accretion expense	1,577	817
Ending balance	50,862	35,371
Less: current portion	6,499	6,822
Noncurrent asset retirement obligation	$44,363	$28,549

(1) $14.3 million of the liability is a result of the Gulf of Mexico Pipeline acquisition.

We are required to establish security against potential obligations relating to the abandonment of certain transmission assets that may be imposed on the previous owner by applicable regulatory authorities. We have deposited $5.0 million with a third party to secure our performance on these potential obligations. These deposits are included in Restricted cash in our consolidated balance sheets as of December 31, 2016 and 2015.

12. Debt Obligations

Our outstanding debt consists of the following as of December 31, 2016 (in thousands):

	Credit Agreement (1)	8.5% Senior Notes due 2021	3.77% Senior Notes due 2031	Other Debt	Total
Balance	$ 711,250	$300,000	$60,000	$2,782	$1,074,032
Less unamortized deferred financing costs and discount	—	(8,691)	(2,345)	—	(11,036)
Subtotal	711,250	291,309	57,655	2,782	1,062,996
Less current portion	—	—	(1,676)	(2,782)	(4,458)
Non-current portion	$ 711,250	$291,309	$55,979	$—	$1,058,538

Our outstanding debt consists of the following as of December 31, 2015 (in thousands):

	Credit Agreement (1)	Other Debt	Total
Balance	$ 525,100	$2,338	$527,438
Less current portion	—	(2,338)	(2,338)
Non-current portion	$ 525,100	$—	$525,100

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(1) Unamortized deferred financing costs related to the Credit Agreement are included in Other assets, net.

Credit Agreement

Effective as of April 25, 2016, the Partnership entered into the Second Amendment to the Amended and Restated Credit Agreement (as amended, the "Credit Agreement"), which provides for maximum borrowings up to $750.0 million, with the ability to further increase the borrowing capacity to $900.0 million subject to lender approval. We can elect to have loans under our Credit Agreement bear interest either at a Eurodollar-based rate, plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (i) the Federal Funds Rate plus 0.50%, (ii) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate," or (iii) the Eurodollar Rate plus 1.00% plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan under the Credit Agreement.

Our obligations under the Credit Agreement are secured by a lien on substantially all of our assets. Advances made under the Credit Agreement are guaranteed on a senior unsecured basis by certain of our subsidiaries (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. The terms of the Credit Agreement include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. The remaining principal balance and any accrued and unpaid interest will be due and payable in full at maturity, on September 5, 2019.

On September 30, 2016, in connection with the 3.77% Senior Note Purchase Agreement, the Partnership entered into the Limited Waiver and Third Amendment to the Credit Agreement, which among other things, (i) allows Midla Holdings (as defined below), for so long as the 3.77% Senior Notes are outstanding, to be excluded from guaranteeing the obligations under the Credit Agreement and being subject to certain convents thereunder, (ii) releases the lien granted under the original credit agreement on D-Day's equity interests in Delta House FPS, LLC, and (iii) deems the equity interests in Delta House FPS, LLC to be excluded property under the Credit Agreement. All other terms under the Credit Agreement remain the same.

On November 18, 2016, the Partnership entered into the Fourth Amendment to the Amended and Restated Credit Agreement. The Fourth Amendment (i) modifies certain investment covenants to reflect the recently completed incremental acquisition of additional interests in Delta House Class A Units (ii) permits JPE's existing credit facility (the "JPE Credit Facility") to remain in place during the time period between (a) the consummation of the JPE Merger and (b) the payoff of the JPE Credit Facility, (iii) permits the joining of JPE and its subsidiaries as guarantors under the Credit Agreement, and (iv) permits the integration of JPE and its subsidiaries into the Partnership's ownership structure.

The Credit Agreement contains certain financial covenants, including a consolidated total leverage ratio which requires our indebtedness not to exceed 4.75 times adjusted consolidated EBITDA for the prior twelve month period adjusted in accordance with the Credit Agreement (except for the current and subsequent two quarters after the consummation of a permitted acquisition, at which time the covenant is increased to 5.25 times adjusted consolidated EBITDA) and a minimum interest coverage ratio that requires our adjusted consolidated EBITDA to exceed consolidated interest charges by not less than 2.50 times. The financial covenants in our Credit Agreement may limit the amount available to us for borrowing to less than $750.0 million. In addition to the financial covenants described above, the Credit Agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

For the years ended December 31, 2016, 2015 and 2014, the weighted average interest rate on borrowings under our Credit Agreement was approximately 4.29%, 3.67%, and 3.80%, respectively.

As of December 31, 2016, our consolidated total leverage ratio was 4.07 and our interest coverage ratio was 7.43, which were both in compliance with the related requirements of our Credit Agreement. At December 31, 2016 and 2015, letters of credit outstanding under the Credit Agreement were $7.4 million and $1.8 million, respectively. As of December 31, 2016, we had approximately $711.3 million of borrowings and $7.4 million of letters of credit outstanding under the Credit Agreement resulting in $31.3 million of available borrowing capacity.

As of December 31, 2016, we were in compliance with the covenants included in the Credit Agreement. Our ability to maintain compliance with the leverage and interest coverage ratios included in the Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions, or drop down transactions, as well as the associated financing for such initiatives.

The carrying value of amounts outstanding under the Partnership’s Credit Agreement approximates the related fair value, as interest charges vary with market rates conditions. On March 8, 2017, the Partnership entered into the Second Amended and Restated Credit Agreement, which increased our borrowing capacity from $750.0 million to $900.0 million and provided for an accordion feature that will permit, subject to the customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion. Please see Note 23.

8.50% Senior Notes

On December 28, 2016, the Partnership and American Midstream Finance Corporation, our wholly-owned subsidiary (the “Co-Issuer” and together with the Partnership, the “Issuers”), completed the issuance and sale of the 8.50% Senior Notes. The 8.50% Senior Notes are jointly and severally guaranteed by the Partnership’s existing direct and indirect wholly owned subsidiaries (other than the Co-Issuer) and certain of the Partnership’s future subsidiaries (the “Guarantors”). The 8.50% Senior Notes rank equal in right of payment with all existing and future senior indebtedness of the Issuers, and senior in right of payment to any future subordinated indebtedness of the Issuers. The 8.50% Senior Notes were issued at par and provided approximately $294.0 million in proceeds, after deducting the initial purchasers' discount of $6.0 million. This amount was deposited into escrow pending completion of the JPE Merger and is included in Restricted cash on our consolidated balance sheet as of December 31, 2016. The Partnership also incurred $2.7 million of direct issuance costs resulting in net proceeds related to the 8.50% Senior Notes of $291.3 million.

Upon the closing of the JPE Merger and the satisfaction of other conditions related thereto, the restricted cash was released from escrow and was used to repay and terminate JPE's revolving credit facility and reduce borrowings under the Partnership’s Credit Agreement.

The 8.50% Senior Notes will mature on December 15, 2021 with interest payable in arrears on June 15 and December 15, commencing June 15, 2017.

At any time prior to December 15, 2018, the Issuers may redeem up to 35% of the aggregate principal amount of 8.50% Senior Notes, at a redemption price of 108.50% of the principal amount, plus accrued and unpaid interest to the redemption date, in an amount not greater than the net cash proceeds of one or more equity offerings by the Partnership, provided that:

- at least 65% of the aggregate principal amount of the 8.50% Senior Notes remains outstanding immediately after such redemption (excluding 8.50% Senior Notes held by the Partnership and its subsidiaries); and

- the redemption occurs within 180 days of the closing of each such equity offering.

Prior to December 15, 2018, the Issuers may redeem all or part of the 8.50% Senior Notes, at a redemption price equal to the sum of:

- the principal amount thereof, plus
- the make whole premium (as defined in the Indenture) at the redemption date, plus
- accrued and unpaid interest, to the redemption date.

On and after December 15, 2018, the Issuers may redeem all or a part of the 8.50% Senior Notes, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest, if redeemed during the twelve-month period beginning on December 15 of the years indicated below:

Year	Percentage
2018	104.250%
2019	102.125%
2020 and thereafter	100.000%

The Indenture restricts the Partnership's ability and the ability of certain of its subsidiaries to, among other things: (i) incur, assume or guarantee additional indebtedness, issue any disqualified stock or issue preferred units, (ii) create liens to secure indebtedness, (iii) pay distributions on equity securities, redeem or repurchase equity securities or redeem or repurchase subordinated securities, (iv) make investments, (v) restrict distributions, loans or other asset transfers from restricted subsidiaries, (vi) consolidate with or merge with or into, or sell substantially all of its properties to, another person, (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries, (viii) enter into transactions with affiliates, (ix) engage in certain business activities and (x) enter into sale and leaseback transactions. These covenants are subject to a number of important exceptions and qualifications. If at any time the 8.50% Senior Notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and no Default or Event of Default (as each are defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.
The carrying value of the 8.50% Senior Notes as of December 31, 2016 approximates the related fair value as of that date as the Senior Notes were issued on December 28, 2016.

3.77% Senior Notes

On September 30, 2016, Midla Financing, LLC ("Midla Financing"), American Midstream (Midla), LLC ("Midla"), and Mid Louisiana Gas Transmission LLC ("MLGT" and together with Midla, the "Note Guarantors") entered into a Note Purchase and Guaranty Agreement with certain institutional investors (the "Purchasers") whereby Midla Financing issued $60.0 million in aggregate principal amount of 3.77% Senior Notes due June 30, 2031. Principal and interest on the 3.77% Senior Notes is payable in installments on the last business day of each quarter beginning June 30, 2017 with the remaining balance payable in full on June 30, 2031. The average quarterly principal payment is approximately $1.1 million. The 3.77% Senior Notes were issued at par and provided net proceeds of approximately $57.7 million after deducting related issuance costs of $2.3 million.

Net proceeds from the 3.77% Senior Notes are restricted and will be used to fund project costs incurred in connection with the construction of the Midla-Natchez Line, the retirement of Midla's existing 1920's pipeline, the move of our Baton Rouge operations to the MLGT system, and the reconfiguration of the DeSiard compression system and all related ancillary facilities. These proceeds can also be used to pay costs incurred in connection with the issuance of the 3.77% Senior Notes, and for general corporate purposes of Midla Financing. As of December 31, 2016, Restricted cash includes $24.5 million from the issuance of the 3.77% Senior Notes.

The Note Purchase Agreement includes customary representations and warranties, affirmative and negative covenants (including financial covenants), and events of default that are customary for a transaction of this type. Midla Financing must maintain a debt service reserve account containing six months of principal and interest payments, and Midla Financing and the Note Guarantors (including any entities that become guarantors under the terms of the 3.77% Senior Note Purchase Agreement) are restricted from making distributions until June 30, 2017, unless the debt service coverage ratio is not less than, and is not projected to be for the following 12 calendar months less than, 1.20:1.00, and unless certain other requirements are met.

In connection with the 3.77% Senior Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing's related obligations. Also, Midla Financing and the Note Guarantors granted a security interest in substantially all of their tangible and intangible personal assets, including the membership interests in each Note Guarantor held by Midla Financing, and Midla Holdings pledged the membership interests in Midla Financing to the Collateral Agent.

As of December 31, 2016, the fair value of the 3.77% Senior Notes was $54.6 million.This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

13. Convertible Preferred Units

Our convertible preferred units consist of the following (in thousands):

	Series A		Series C		Series D	
	Units	$	Units	$	Units	$
December 31, 2013	5,279	$94,811	—	$—	—	$—
Issuance of units	—	—	—	—	—	—
Paid in kind unit distributions	466	13,154	—	—	—	—
December 31, 2014	5,745	107,965	—	—	—	—
Issuance of units	2,571	44,769	—	—	—	—
Paid in kind unit distributions	894	16,978	—	—	—	—
December 31, 2015	9,210	169,712	—	—	—	—
Issuance of units	—	—	8,571	115,457	2,333	34,475
Paid in kind unit distributions	897	11,674	221	2,772	—	—
December 31, 2016	10,107	$181,386	8,792	$118,229	2,333	$34,475

Affiliates of our General Partner hold and participate in quarterly distributions on our convertible preferred units, with such distributions being made in cash, paid-in-kind units or a combination thereof, at the election of the Board of Directors of our General Partner, although quarterly distribution on our Series D Units will only be paid in cash. The convertible preferred unitholders have the right to receive cumulative distributions in the same priority and prior to any other distributions made in respect of any other partnership interests.

To the extent that any portion of a quarterly distribution on our convertible preferred units to be paid in cash exceeds the amount of cash available for such distribution, the amount of cash available will be paid to our convertible preferred unitholders on a pro rata basis while the difference between the distribution and the available cash will become arrearages and accrue interest until paid.

Series A-1 Convertible Preferred Units

On April 15, 2013, the Partnership, our General Partner and AIM Midstream Holdings entered into agreements with HPIP, pursuant to which HPIP acquired 90% of our General Partner and all of our subordinated units from AIM Midstream Holdings and contributed the High Point System and $15.0 million in cash to us in exchange for 5,142,857 of our Series A-1 Units.
The Series A-1 Units receive distributions prior to distributions to our common unitholders. The distributions on the Series A-1 Units are equal to the greater of $0.50 per unit or the declared distribution to common unitholders. The Series A-1 Units may be converted into common units on a one-to-one basis, subject to customary anti-dilutive adjustments, at the option of the unitholders on or any time after January 1, 2014. As of December 31, 2016, the

conversion price is $15.87.

Upon any liquidation and winding up of the Partnership or the sale of substantially all of its assets, the holders of Series A-1 Units will generally be entitled to receive, in preference to the holders of any of the Partnership's other equity securities, but in parity with all convertible preferred units, an amount equal to the sum of $15.87 multiplied by the number of Series A-1 Units owned by such holders, plus all accrued but unpaid distributions on such Series A Units.

Prior to the consummation of any recapitalization, reorganization, consolidation, merger, spin-off or other business combination in which the holders of common units are to receive securities, cash or other assets (a "Partnership Event"), we are obligated to make an irrevocable written offer, subject to consummation of the Partnership Event, to each holder of Series A Units to redeem all (but not less than all) of such holder's Series A-1 Units for a per unit price payable in cash as described in the Partnership Agreement.

Upon receipt of such a redemption offer from us, each holder of Series A-1 Units may elect to receive such cash amount or a preferred security issued by the person surviving or resulting from such Partnership Event and containing provisions substantially equivalent to the provisions set forth in the Partnership Agreement with respect to the Series A-1 Units without material abridgement.

Except as provided in the Partnership Agreement, the Series A-1 Units have voting rights that are identical to the voting rights of the common units and will vote with the common units as a single class, with each Series A-1 Unit entitled to one vote for each common unit into which such Series A-1 Unit is convertible.

As conversion is at the option of the holder and redemption is contingent upon a future event which is outside the control of the Partnership, the Series A-1 Units have been classified as mezzanine equity in the consolidated balance sheets.

Under the Partnership Agreement, distributions on Series A-1 Units were made with paid-in-kind Series A-1 Units, cash or a combination thereof, at the discretion of the Board of Directors, through the distribution for the quarter ended March 31, 2016. The Partnership was previously required to pay distributions on the Series A-1 Units with a combination of paid-in-kind units and cash.

Series A-2 Convertible Preferred Units

On March 30, 2015 and June 30, 2015, we entered into two Series A-2 Convertible Preferred Unit Purchase Agreements with Magnolia Infrastructure Partners ("Magnolia") an affiliate of HPIP pursuant to which the Partnership issued, in separate private placements, newly-designated Series A-2 Units (the “Series A-2 Units”) representing limited partnership interests in the Partnership. As a result, the Partnership issued a total of 2,571,430 Series A-2 Units for approximately $45.0 million in aggregate proceeds during the year ended December 31, 2015. The Series A-2 Units will participate in distributions of the Partnership along with common units in a manner identical to the existing Series A-1 Units (together with the Series A-2 Units, the "Series A Units"), with such distributions being made in cash or with paid-in-kind Series A Units at the election of the Board of Directors of our General Partner.

On July 27, 2015, we amended our Partnership Agreement to grant us the right (the “Call Right”) to require the holders of the Series A-2 Units to sell, assign and transfer all or a portion of the then outstanding Series A-2 Units to us for a purchase price of $17.50 per Series A-2 Unit (subject to appropriate adjustment for any equity distribution, subdivision or combination of equity interests in the Partnership). We may exercise the Call Right at any time, in connection with our or our affiliate’s acquisition of assets or equity from ArcLight Energy Partners Fund V, L.P., or one of its affiliates, for a purchase price in excess of $100 million. We may not exercise the Call Right with respect to any Series A-2 Units that a holder has elected to convert into common units on or prior to the date we have provided notice of our intent to exercise the Call Right, and we may also not exercise the Call Right if doing so would result in a default under any of our or our affiliates’ financing agreements or obligations. As of December 31, 2016, the conversion price is $15.87.

Series C Convertible Preferred Units

On April 25, 2016, the Partnership issued 8,571,429 of its Series C Units to an ArcLight affiliate in connection with the Emerald Transactions described in Note 2.

The Series C Units have voting rights that are identical to the voting rights of the common units and will vote with the common units as a single class on an as converted basis, with each Series C Unit initially entitled to one vote for each common unit into which such Series C Unit is convertible. The Series C Units also have separate class voting rights on any matter, including a merger, consolidation or business combination, that adversely affects, amends or modifies any of the rights, preferences, privileges or terms of the Series C Units. The Series C Units are convertible in whole or in part into common units at any time. The number of common units into which a Series C Unit is convertible will be an amount equal to the sum of $14.00 plus all accrued and accumulated but unpaid distributions, divided by the conversion price. The sale of the Series C Units was exempt from registration under Securities Act pursuant to Rule 4(a)(2) under the Securities Act.

In the event that the Partnership issues, sells or grants any common units or convertible securities at an indicative per common unit price that is less than $14.00 per common unit (subject to customary anti-dilution adjustments), then the conversion price will be adjusted according to a formula to provide for an increase in the number of common units into which Series C Units are convertible. As of December 31, 2016, the conversion price is $13.95.

Prior to consummating any recapitalization, reorganization, consolidation, merger, spin-off or other business combination in which the holders of common units are to receive securities, cash or other assets, we are obligated to make an irrevocable written offer, subject to consummating the Partnership Event, to the holders of Series C Units to redeem all (but not less than all) of the Series C Units for a price per Series C Unit payable in cash as described in the Partnership Agreement.

Upon receipt of a redemption offer, each holder of Series C Preferred Units may elect to receive the cash amount or a preferred security issued by the person surviving or resulting from the Partnership Event and containing provisions substantially equivalent to the provisions set forth in the Fifth Amended and Restated Partnership Agreement with respect to the Series C Preferred Units without material abridgement.

Upon any liquidation and winding up of the Partnership or the sale of substantially all of the assets of the Partnership, the holders of Series C Units generally will be entitled to receive, in preference to the holders of any of the Partnership's other equity securities but in parity with all convertible preferred units, an amount equal to the sum of the $14.00 multiplied by the number of Series C Units owned by such holders, plus all accrued but unpaid distributions.

At any time prior to April 25, 2017, the Partnership has the right (the “Series C Call Right”) to require the holders of the Series C Units to sell, assign and transfer all or a portion of the then outstanding Series C Units for a purchase price of $14.00 per Series C Unit (subject to customary anti-dilution adjustments), plus all accrued but unpaid distributions on each Series C Unit.

The Partnership may not exercise the Series C Call Right if the holder has elected to convert it into common units on or prior to the date the Partnership has provided notice of its intent to exercise its Series C Call Right, and may not exercise the Series C Call Right if doing so would violate applicable law or result in a default under any financing agreement or obligation of the Partnership or its affiliates.

In connection with the issuance of the Series C Units, the Partnership issued the holders a warrant to purchase up to 800,000 common units at an exercise price of $7.25 per common unit (the "Series C Warrant"). The Series C Warrant is subject to standard anti-dilution adjustments and is exercisable for a period of seven years.

On April 25, 2017, the number of common units that may be purchased pursuant to the exercise of the Series C Warrant will be adjusted by an amount, rounded to the nearest whole common unit, equal to the product obtained by the following calculation: (i) 400,000 multiplied by (ii) (A) the Series C Issue Price multiplied by the number of Series C Units then outstanding less $45.0 million divided by (B) the Series C Issue Price multiplied by the number of Series C Units issued, less $45.0 million.

Any Series C Units issued in-kind as a distribution to holders of Series C Units (“Series C PIK Units”) will increase the number of common units that can be purchased upon exercise of the Series C Warrant by an amount, rounded to the nearest whole common unit, equal to the product obtained by the following calculation: (i) the total number of common units into which each Series C Warrant may be exercised immediately prior to the most recent issuance of the Series C PIK Units multiplied by (ii) (A) the total number of outstanding Series C Units immediately after the most recent issuance of Series C PIK Units divided by (B) the total number of outstanding Series C Units immediately prior to the most recent issuance of Series C PIK Units.

The fair value of the Series C Warrant was determined using a market approach that utilized significant inputs which are not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. The estimated fair value of $4.41 per warrant unit was determined using a Black-Scholes model and the following significant assumptions: i) a dividend yield of 18%, ii) common unit volatility of 42% and iii) the seven-year term of the warrant to arrive at an aggregate fair value of $4.5 million.

Series D Convertible Preferred Units

On October 31, 2016, Partnership issued 2,333,333 shares of its newly-designated Series D Units to an ArcLight affiliate at a price of $15.00 per unit, less a 1.5% closing fee, in connection with the Delta House transaction described in Note 2. The related agreement provides that if any of the Series D Units remain outstanding on June 30, 2017, the Partnership will issue the holder of the Series D Units a warrant (the “Series D Warrant”) to purchase 700,000 common units representing limited partnership interests with an exercise price of $22.00 per common unit. The fair value of the conditional Series D Warrant at the time of issuance was immaterial.

The Series D Units are entitled to quarterly distributions payable in arrears equal to the greater of $0.4125 and the cash distribution that the Series D Units would have received if they had been converted to common units immediately prior to the beginning of the the quarter. The Series D Units also have separate class voting rights on any matter, including a merger, consolidation or business combination, that adversely affects, amends or modifies any of the rights, preferences, privileges or terms of the Series

D Units. The Series D Units are convertible in whole or in part into common units at the election of the holder of the Series D Unit at any time after June 30, 2017. As of the date of issuance, the conversion rate for each Series D Unit was one -to-one (the “Conversion Rate”). As of December 31, 2016, the conversion price is $14.98.

In the event that the Partnership issues, sells or grants any common units or securities convertible into common units at an indicative per common unit price that is less than $15.00 per unit (subject to customary anti-dilution adjustments), then the Conversion Rate will be adjusted according to a formula to provide for an increase in the number of common units into which Series D Units are convertible.

Prior to the consummation of any recapitalization, reorganization, consolidation, merger, spin-off or other business combination in which the holders of Common Units are to receive securities, cash or other assets (a “Partnership Event”), the Partnership is obligated to make an irrevocable written offer, subject to consummation of the Partnership Event, to the holders of Series D Units to redeem all (but not less than all) of the Series D Units for a price per Series D Unit payable in cash as described in the Partnership Agreement.

Upon receipt of a redemption offer, each holder of Series D Units may elect to receive the cash amount or a preferred security issued by the person surviving or resulting from the Partnership Event.

Upon any liquidation and winding up of the Partnership or the sale of substantially all of the assets of the Partnership, the holders of Series D Units generally will be entitled to receive, in preference to the holders of any of the Partnership's other equity securities but in parity with all convertible preferred units, an amount equal to the sum of the $15.00 multiplied by the number of Series D Units owned by such holders, plus all accrued but unpaid distributions.

At any time prior to June 30, 2017, the Partnership has the right (the “Series D Call Right”) to redeem the Series D Units for the product of (i) the sum of $15.00 and all accrued and accumulated but unpaid distributions for each Series D Unit (including a proportionate amount of the distribution on each Series D Unit that has accrued for the quarter in which the redemption occurs); and (ii) 1.03.

14. Partners' Capital

Outstanding Units

The following table presents unit activity (in thousands):

	General Partner Interest	Limited Partner Interest	Series B Convertible Units
Balances at December 31, 2013	185	7,414	—
Initial issuance of Series B Units	—	—	1,168
Issuance of Series B Units	—	—	87
LTIP vesting	—	41	—
Issuance of GP units	207	—	—
Exercise of warrants	—	300	—
Issuance of common units	—	14,915	—
Balances at December 31, 2014	392	22,670	1,255
Issuance of Series B Units	—	—	95
LTIP vesting	—	105	—
Exercise of unit options	—	152	—
Issuance of GP units	144	—	—
Issuance of common units	—	7,500	—
Balances at December 31, 2015	536	30,427	1,350
Conversion of Series B Units	—	1,350	(1,350)
Return of escrow units	—	(1,034)	—
LTIP vesting	—	246	—
Issuance of GP units	144	—	—
Issuance of common units	—	248	—
Balances at December 31, 2016	680	31,237	—

Our capital accounts are comprised of approximately 1.3% notional General Partner interest and 98.7% limited partner interests as of December 31, 2016. Our limited partners have limited rights of ownership as provided for under our Partnership Agreement and the right to participate in our distributions. Our General Partner manages our operations and participates in our distributions, including certain incentive distributions pursuant to the incentive distribution rights that are non-voting limited partner interests held by our General Partner. Pursuant to our Partnership Agreement, our General Partner participates in losses and distributions based on its interest. The General Partner's participation in the allocation of losses and distributions are not limited and therefore, such participation can result in a deficit to its respective capital account. As such, allocation of losses and distributions for previous transactions between entities under common control have resulted in a deficit to the General Partner's capital account included in our consolidated balance sheets.

Series B Convertible Preferred Units

Effective January 31, 2014, the Partnership issued 1,168,225 Series B Units to its General Partner in exchange for approximately $30.0 million to fund a portion of the Lavaca acquisition described in Note 2. The Series B Units participated in distributions of the Board of Directors of our General Partner along with common units, with such distributions being made in cash distributions or with paid-in-kind Series B Units at the election of the Partnership. The Series B Units were issued in a private placement in reliance upon an exemption from the registration requirements of the Securities Act of 1933 pursuant to Section 4(a)(2) thereof and the safe harbor provided by Rule

506 of Regulation D promulgated thereunder. On February 1, 2016, all outstanding Series B Units were converted on a one-for-one basis into common units.

The Board of Directors of our General Partner elected to pay the Series B distributions using paid-in-kind Series B Units. For the years ended December 31, 2015 and 2014, the Partnership issued 94,923 and 86,461, respectively, of paid-in-kind Series B Units with a fair value of $1.4 million and $2.2 million, respectively.

Equity Offerings

In October 2015, the Partnership and certain of its affiliates entered into an agreement with a group of investment banks under which it may issue up to $100 million of its common units in at the market (“ATM”) offerings. During 2016, the Partnership issued 248,561 common units under this program resulting in net proceeds of $2.9 million after deducting related offering costs of $0.3 million. The net proceeds were used to repay amounts outstanding under the Credit Agreement. At December 31, 2016, $96.8 million remained available under the ATM program.

In September 2015, the Partnership sold 7,500,000 of its common units in a public offering at a price to the public of $11.31 per common unit. The net proceeds of approximately $81.0 million were used to fund a portion of the Delta House investment described in Note 2. In October 2016, the Partnership issued an additional 151,937 common units at a price of $11.31 per unit pursuant to the partial exercise of the underwriters' overallotment option, resulting in net proceeds of approximately $1.7 million.

In October 2014, the Partnership acquired Costar from Energy Spectrum Partners VI LP and Costar Midstream Energy, LLC which was funded, in part, with 6,892,931 of common units issued directly to Energy Spectrum and Costar Midstream Energy LLC. In February 2016, the Partnership reached a settlement of certain indemnification claims with the Costar sellers whereby approximately 1,034,483 common units held in escrow were returned to the Partnership.

In July 2014, the Partnership entered into a common unit purchase agreement with certain institutional investors, which was subsequently amended on August 15, 2014, to provide for the sale of 4,622,352 common units representing limited partner interests in the Partnership in a private placement at a price of $25.8075 per common unit (reflecting an adjustment for the Partnership's second quarter distribution of $0.4625 per unit), for cash consideration of $119.3 million.

In January 2014, the Partnership sold 3,400,000 of its common units in a public offering at a price of $26.75 per common unit. The Partnership used the net proceeds of $86.9 million to fund a portion of the Lavaca Acquisition described in Note 2.

General Partner Units

In order to maintain its ownership percentage, we received proceeds of $2.0 million from our General Partner as consideration for the issuance of 143,900 additional notional general partner units for the year ended December 31, 2016 and proceeds of $1.9 million for the issuance of 143,517 additional notional general partner units for the year ended December 31, 2015.

Distributions

We made the following distributions (in thousands):

	Years Ended December 31,		
	2016	2015	2014
Series A Units			
Cash:			
Paid	$4,935	$—	$2,658
Accrued	2,514	—	—
Paid-in-kind units	11,674	16,978	13,154
Total	19,123	16,978	15,812
Series B Units			
Paid-in-kind units	—	1,373	2,220
Total	—	1,373	2,220
Series C Units			
Cash:			
Paid	3,089	—	—
Accrued	3,626	—	—
Paid-in-kind units	2,772	—	—
Total	9,487	—	—
Series D Units			
Cash:			
Paid	—	—	—
Accrued	963	—	—
Paid-in-kind units	—	—	—
Total	963	—	—
Limited Partner Units			
Cash:			
Paid	53,500	46,597	22,656
Accrued	—	—	—
Total	53,500	46,597	22,656
General Partner Units			
Cash:			
Paid	2,551	6,789	2,695
Accrued	—	—	—
Additional Blackwater acquisition consideration	5,000	—	—
Total	7,551	6,789	2,695
Summary			
Cash			
Paid	64,075	53,386	28,009
Accrued	7,103	—	—
Paid-in-kind units	14,446	18,351	15,374

Additional Blackwater acquisition consideration	5,000	—	—
Total	$90,624	$71,737	$43,383

On January 26, 2017, the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit or $1.65 per common unit on an annualized basis. The distribution was paid on February 13, 2017, to unitholders of record as of the close of business on February 6, 2017. Accrued cash distributions on our preferred convertible units were also paid in February 2017.

The fair value of the paid-in-kind distributions was determined using the market and income approaches, requiring significant inputs which are not observable in the market and thus represent a Level 3 measurements as defined by ASC 820. Under the income approach, the fair value estimates for all years presented were based on i) present value of estimated future contracted distributions, ii) option values ranging from $0.02 per unit to $9.68 per unit using a Black-Scholes model, iii) assumed discount rates ranging from 5.57% to 10.0% and iv) assumed growth rates of 1.0%.

15. Net Income (Loss) per Limited Partner Unit

Net income (loss) is allocated to the General Partner and the limited partners in accordance with their respective ownership percentages, after giving effect to distributions on our convertible preferred units and General Partner units, including incentive distribution rights. Unvested unit-based compensation awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net limited partners' net income (loss) per common unit. Basic and diluted limited partners' net income (loss) per common unit is calculated by dividing limited partners' interest in net income (loss) by the weighted average number of outstanding limited partner units during the period.

The calculation of basic and diluted limited partners' net income (loss) per common unit is summarized below (in thousands, except per unit amounts):

	Years Ended December 31,		
	2016	2015	2014
Net income (loss) from continuing operations	$(666)	$(127,375)	$(97,195)
Less: Net income attributable to noncontrolling interests	2,804	25	214
Net (income) loss from continuing operations attributable to the Partnership	(3,470)	(127,400)	(97,409)
Less:			
Distributions on Series A Units	19,138	16,978	14,492
Distributions on Series C Units	9,487	—	—
Distributions on Series D Units	963	—	—
Distributions on Series B Units	—	1,373	2,220
General partner's distributions	2,550	6,790	2,694
General partner's share in undistributed loss	(1,140)	(2,569)	(1,820)
Net loss from continuing operations attributable to Limited Partners	(34,468)	(149,972)	(114,995)
Net loss from discontinued operations attributable to Limited Partners	—	(80)	(603)
Net loss attributable to Limited Partners	$(34,468)	$(150,052)	$(115,598)
Weighted average number of common units used in computation of Limited Partners' net loss per common unit - basic and diluted	31,043	24,983	13,472
Limited Partners' net loss from continuing operations per unit (basic and diluted)	$(1.11)	$(6.00)	$(8.54)
Limited Partners' net loss from discontinued operations per unit (basic and diluted)	—	—	(0.04)
Limited Partners' net loss per common unit - basic and diluted (1)	$(1.11)	$(6.00)	$(8.58)

(1) Potential common unit equivalents are antidilutive for all periods and, as a result, have been excluded from the determination of diluted limited partners' net income (loss) per common unit.

F-35

16. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 19, 2015, the Board of Directors of our General Partner approved the Third Amended and Restated Long-Term Incentive Plan to, among other things, increase the number of common units authorized for issuance by 6,000,000 common units. On February 11, 2016, the unitholders approved the Third Amended and Restated Long-Term Incentive Plan (as amended and as currently in effect as of the date hereof, the "LTIP"). At December 31, 2016, 2015 and 2014, there were 5,017,528, 15,484 and 688,976 common units, respectively, available for future grant under the LTIP.

All equity-based awards issued under the LTIP consist of phantom units, distribution equivalent rights ("DER") or option grants. DERs and options have been granted on a limited basis. Future awards may be granted at the discretion of the Compensation Committee and subject to approval by the Board of Directors of our General Partner.

Phantom Unit Awards. Ownership in the phantom unit awards is subject to forfeiture until the vesting date. The LTIP is administered by the Compensation Committee of the Board of Directors of our General Partner, which at its discretion, may elect to settle such vested phantom units with a number of common units equivalent to the fair market value at the date of vesting in lieu of cash. Although our General Partner has the option to settle vested phantom units in cash, our General Partner has not historically settled these awards in cash. Under the LTIP, phantom units typically vest in increments of 25% on each grant anniversary date and do not contain any vesting requirements other than continued employment.

In December 2015, the Board of Directors of our General Partner approved a grant of 200,000 phantom units under the LTIP which contain DERs to the extent the Partnership’s Series A Preferred Unitholders receive distributions in cash. These units will vest on the three year anniversary of the date of grant, subject to acceleration in certain circumstances.

The following table summarizes activity in our phantom unit-based awards for the years ended December 31, 2016, 2015 and 2014:

	Units	Weighted-Average Grant Date Fair Value Per Unit	Aggregate Intrinsic Value [1] (In thousands)
Outstanding shares at December 2013	75,529	$ 17.62	$ 2,045
Granted	188,946	20.80	
Forfeited	(12,009)	(18.28)	
Vested	(51,334)	(20.89)	
Outstanding shares at December 2014	201,132	$ 19.85	$ 3,964
Granted	546,329	12.25	
Forfeited	(31,298)	(15.62)	
Vested	(146,404)	(18.47)	
Outstanding shares at December 2015	569,759	$ 13.15	$ 4,609
Granted	1,374,226	2.14	
Forfeited	(411,794)	(2.60)	
Vested	(286,348)	(12.18)	
Outstanding shares at December 2016	1,245,843	$ 4.72	$ 22,674

(1) The intrinsic value of phantom units was calculated by multiplying the closing market price of our underlying stock on December 31, 2016, 2015 and 2014 by the number of phantom units.

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our common units at the grant date. Compensation expense related to these awards for the years ended December 31, 2016, 2015, and 2014 was $3.6 million, $3.8 million and $1.5 million, respectively, and is included in Corporate expenses and Direct operating expenses in our consolidated statements of operations and the equity compensation expense in our consolidated statements of changes in partners' capital and noncontrolling interests.

The total fair value of units at the time of vesting was $2.4 million, $2.6 million, and $1.4 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Equity compensation expense related to unvested phantom awards not yet recognized at December 31, 2016 was $4.2 million and the weighted average period over which this expense is expected to be recognized as of December 31, 2016 is approximately 2.2 years.

Performance and Service Condition Awards. In November 2015, the Board of Directors of our General Partner modified awards that introduced certain performance and service conditions that were probable of being achieved, amounting to $2.0 million payable to certain employees. During the third quarter of 2016, we settled $1.0 million of the obligation in cash while in the fourth quarter of 2016, forfeitures reduced the total payable amount from $2.0 million to $1.5 million. These awards are accounted for as liability classified awards. Compensation expense related to these awards for the years ended December 31, 2016 and 2015 was $0.9 million and $0.5 million, respectively, and is included in Direct operating expenses in our consolidated statements of operations. Compensation expense related to unvested awards not yet recognized at December 31, 2016 was $0.1 million.

Option to Purchase Common Units. In December 2015, the Board of Directors of our General Partner approved the grant of an option to purchase 200,000 common units at an exercise price per unit equal to $7.50. The grant will vest on January 1, 2019, subject to acceleration in certain circumstances, and will expire on March 15th of the calendar year following the calendar year in which it vests.

In August 2016, the Board of Directors of our General Partner approved the grant of an option to purchase 30,000 common units at an exercise price per unit equal to $12.00. The grant will vest on July 31, 2019, subject to continued employment, and will expire on July 31st of the calendar year following the calendar year in which it vests.

In September 2016, the Board of Directors of our General Partner approved the grant of an option to purchase 45,000 common units of the Partnership at an exercise price per unit equal to $13.88. The options will vest at a rate of 25% per year. The options will expire on September 30th of the calendar year following the calendar year in which it vests.

The Black-Scholes pricing model was used to determine the fair value of our options grants using the following assumptions:

	Years Ended December 31,	
	2016	2015
Weighted average common unit price volatility	61.1%	47.0%
Expected distribution yield	12.6%	26.3%
Weighted average expected term (in years)	4.10	3.5
Weighted average risk-free rate	1.1 %	1.3 %

The weighted average unit price volatility was based upon the historical volatility of our common units. The expected distribution yield was based on an annualized distribution divided by the closing unit price on the date of grant. The risk-free rate was based on the U.S. Treasury yield curve in effect on the date of grant.

Compensation expense related to these awards was not material for the years ended December 31, 2016 and 2015. Compensation cost related to unvested awards not yet recognized at December 31, 2016 was $0.2 million.

The following table summarizes our option activity for the years ended December 31, 2016 and 2015:

	Units	Weighted-Average Exercise Price	Weighted-Average Grant Date Fair Value per Unit	Aggregate Intrinsic Value [1] (In thousands)	Weighted Average Remaining Contractual Life (Years)

Outstanding at December 31, 2014	—	$ —	$ —	$ —	—
Granted	200,000	7.50	0.33	—	—
Vested	—	—		—	—
Forfeited	—	—		—	—
Outstanding at December 31, 2015	200,000	$ 7.50	$ 0.33	$ 118	4.2
Granted	75,000	13.13	2.65	—	—
Vested	—	—		—	—
Forfeited	—	—		—	—
Outstanding at December 31, 2016	275,000	$ 9.03	$ 0.96	$ 2,522	5.0

(1) The intrinsic value of the stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

17. Income Taxes

With the exception of certain subsidiaries in our Terminals Segment, the Partnership is not subject to U.S. federal or state income taxes as such income taxes are generally borne by our unitholders through the allocation of our taxable income (loss) to them. The State of Texas does impose a franchise tax that is assessed on the portion of our taxable margin which is apportioned to Texas.

Income tax (expense) benefit for the years ended December 31, 2016, 2015 and 2014 is as follows:

	Years Ended December 31,		
	2016	2015	2014
Current income tax expense	$—	$ —	$(10)
Deferred income tax expense	(2,057)	(1,134)	(547)
Effective income tax rate	147.9%	0.9%	0.6 %

A reconciliation of our expected income tax (expense) benefit calculated at the U.S. federal statutory rate of 34% to our actual tax (expense) for the years ended December 31, 2016, 2015 and 2014 is as follows:

	Years Ended December 31,		
	2016	2015	2014
Net income (loss) before income tax expense	$1,391	$(126,241)	$(96,638)
US Federal statutory tax rate	34 %	34 %	34 %
Federal income tax (expense) benefit at statutory rate	(473)	42,922	32,857
Reconciling items:			
Partnership loss not subject to income tax	(1,300)	(43,812)	(33,216)
State and local tax expense	(279)	(103)	(159)
Other	(5)	(141)	(39)
Income tax expense	$(2,057)	$(1,134)	$(557)

The Partnership's deferred tax assets and liabilities as of December 31, 2016 and 2015 are summarized below:

	December 31,	
	2016	2015
Deferred tax assets:		
Net operating loss carryforwards	$6,300	$7,570
Other	577	493
Total deferred tax assets	6,877	8,063
Deferred tax liabilities:		
Property, plant and equipment	(14,735)	(13,889)
Deferred income tax liability, net	$(7,858)	$(5,826)

As of December 31, 2016, certain subsidiaries in our Terminals Segment had net operating loss carryforwards for federal income tax purposes of approximately $16.1 million which begin to expire in 2028.

We recognize the tax benefits from uncertain tax positions if it is more likely than not that the position will be sustained on examination by the taxing authorities. As of December 31, 2016, we have not recognized tax benefits relating to uncertain tax positions.

The preparation of our income tax returns requires the use of management's estimates and interpretations which may be subjected to review by the respective taxing authorities and may result in an assessment of additional taxes, penalties and interest. Tax years subsequent to 2010 remain subject to examination by federal and state taxing authorities.

18. Commitments and Contingencies

Legal proceedings

We are not currently party to any pending litigation or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate impact of any proceedings cannot be predicted with certainly, our management believes that the resolution of any of our pending proceeds will not have a material adverse effect on our financial condition or results of operations.

Environmental matters

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent in our operations and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

Regulatory matters

On October 8, 2014, American Midstream (Midla), LLC ("Midla") reached an agreement in principle with its customers regarding the interstate pipeline that traverses Louisiana and Mississippi in order to provide continued service to its customers while addressing safety concerns with the existing pipeline.

On April 16, 2015, FERC approved the stipulation and agreement (the “Midla Agreement”) relating to the October 8, 2014 regulatory matter and allowing Midla to retire the existing 1920’s pipeline and replace it with the Midla-Natchez Line to serve existing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service. On June 29, 2015, the Partnership filed with FERC for authorization to construct the Midla-Natchez pipeline, which was approved on December 17, 2015. Construction commenced in the second quarter of 2016 with service expected to begin in the first six months of 2017. Under the Midla Agreement, Midla plans to execute long-term agreements seeking to recover its investment in the Midla-Natchez Line.

Exit and disposal costs

On March 9, 2016, management committed to a corporate headquarters relocation plan and communicated that plan to the impacted employees. The plan included relocation assistance or one-time termination benefits for employees who rendered service until their respective termination dates. Charges associated with these termination benefits, which totaled $9.1 million were recognized ratably over the requisite service period and are presented in Corporate expenses in our consolidated statement of operations. At December 31, 2016, payments under the plan had been completed.

Commitments and contractual obligations

The Partnership had the following non-cancelable contractual commitments as of December 31, 2016 (in thousands):

	Total

	Credit Agreement	3.77% Senior Notes	8.50% Senior Notes	Asset Retirement Obligation	Other [1]	
2017	$ —	$ 1,677	$—	$ 6,499	$ 4,144	$ 12,320
2018	—	806	—	—	2,411	3,217
2019	711,250	2,233	—	—	2,547	716,030
2020	—	2,299	—	—	2,081	4,380
2021	—	4,430	300,000	—	1,892	306,322
Thereafter	—	48,555	—	44,363	13,435	106,353
	$ 711,250	$ 60,000	$ 300,000	$ 50,862	$ 26,510	$ 1,148,622

(1) Minimum payments have not been reduced by minimum sublease rentals of $0.2 million.

F-39

For the years ended December 31, 2016, 2015 and 2014, total rental expenses were $13.4 million, $12.0 million, and $5.8 million, respectively.

19. Related-Party Transactions

As described in Note 3, in December 2013 the Partnership acquired Blackwater Midstream Holdings, LLC (“Blackwater”) from affiliates of ArcLight. The acquisition agreement included a provision whereby an ArcLight affiliate would be entitled to an additional $5.0 million of merger consideration based on Blackwater meeting certain operating targets. During the third quarter of 2016, the Partnership determined that it was probable the operating targets would be met in early 2017 and recorded a $5.0 million accrued distribution to the ArcLight affiliate which is included in Accrued expenses and other current liabilities in the accompanying consolidated balance sheet at December 31, 2016.

Employees of our General Partner are assigned to work for the Partnership or other affiliates of our General Partner. Where directly attributable, all compensation and related expenses for these employees are charged directly by our General Partner to American Midstream, LLC, which, in turn, charges the appropriate subsidiary or affiliate. Our General Partner does not record any profit or margin on the expenses charged to us. During the years ended December 31, 2016, 2015, and 2014, related expenses of $41.6 million, $28.7 million, and $22.6 million respectively,which were charged to the Partnership by our General Partner.

During the second quarter of 2014, the Partnership and an affiliate of its General Partner entered into a Management Service Fee arrangement under which the affiliate pays a monthly fee to reimburse the Partnership for administrative expenses incurred on the affiliate’s behalf. For the years ended December 31, 2016, 2015, and 2014, the Partnership recognized related management fee income of $0.8 million, $1.4 million and $0.9 million respectively, under this agreement and recorded such amounts as a reduction of Corporate expenses in the consolidated statements of operations.

As of December 31, 2016, and 2015, the Partnership had $3.9 million and $3.8 million, respectively, due to our General Partner, which has been recorded in Accrued expenses and other current liabilities and relates primarily to compensation. This payable is generally settled on a quarterly basis related to the foregoing transactions.

On November 1, 2016, the Partnership became operator of the Destin and Okeanos pipelines and entered into an operating and administrative management agreements under which the affiliates pay a monthly fee for general and administrative services provided by the Partnership. In addition, the affiliates reimburses the Partnership for certain transition related expenses. For the year ended December 31, 2016, the Partnership recognized $0.4 million of management fee income and $1.0 million as reimbursement of transition related expenses.

American Panther, LLC ("American Panther") is a 60%-owned subsidiary of the Partnership which is consolidated for financial reporting purposes. Pursuant to a related agreement which began in the second quarter of 2016, an affiliate of the non-controlling interest holder provides services to American Panther in exchange for related fees, which in 2016 totaled $0.8 million of Direct operating expenses and $0.4 million of Corporate expenses in the consolidated statement of operations.

The Partnership enters into purchases and sales of natural gas and crude oil with a company whose chief financial officer is the brother of one of our executive officers. During the years ended December 31, 2016, 2015, and 2014, the Partnership recognized revenue of $3.6 million, $6.2 million and $10.1 million, respectively, while purchases from the company totaled $4.3 million, $5.9 million, and $3.7 million, respectively.

20. Supplemental Cash Flow Information

Supplemental cash flows and non-cash transactions consists of the following (in thousands):

	Years Ended December 31,		
	2016	2015	2014
Supplemental cash flow information			
Interest payments, net of capitalized interest	$16,922	$12,013	$6,726
Supplemental non-cash information			
Increase (decrease) in accrued property, plant and equipment purchases	$7,353	$(25,637)	$31,390
Issuance of Series C Units and Warrant in connection with the Emerald Transactions	120,000	—	—
Accrued cash distributions on convertible preferred units	7,103	—	—
Paid-in-kind distributions on convertible preferred units	14,446	16,978	13,154
Paid-in-kind distributions on Series B Units	—	1,373	2,220
Cancellation of escrow units	6,817	—	—
Additional Blackwater acquisition consideration	5,000	—	—
Common unit issuance related to Costar Acquisition	—	—	147,296

21. Reportable Segments

Our operations are located in the United States and are organized into the following reportable segments:

Gathering and Processing

Our Gathering and Processing segment provides "wellhead-to-market" services to producers of natural gas and crude oil, which include transporting raw natural gas and crude oil from various receipt points through gathering systems, treating the raw natural gas, processing raw natural gas to separate the NGLs from the natural gas, fractionating NGLs, and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems.

In 2016, the Gathering and Processing segment had one customer who accounted for 11% of its segment revenue. In 2015, the segment had two customers who each accounted for 12% its segment revenue. In 2014, the segment had two customers who accounted for 33% and 12%, respectively, of its segment revenue.

Transmission

Our Transmission segment transports and delivers natural gas from producing wells, receipt points or pipeline interconnects for shippers and other customers, including local distribution companies ("LDCs"), utilities and industrial, commercial and power generation customers.

In 2016, the Transmission segment had two customers who accounted for 14% and 13%, respectively, of its segment revenue. In 2015, the segment had two customers who accounted for 19% and 16%, respectively, of its segment revenue. In 2014, the segment had two customers who accounted for 43% and 16%, respectively, of its segment revenue.

Terminals

Our Terminals segment provides above-ground storage services at our marine terminals that support various commercial customers, including commodity brokers, refiners and chemical manufacturers to store a range of products, including petroleum products, distillates, chemicals and agricultural products.

In 2016, the Terminals segment had three customers who accounted for 23%, 17%, and 12%, respectively, of its segment revenue. In 2015, the segment had four customers who accounted for 21%, 13%, 13%, and 13%, respectively, of its segment revenue. In 2014, the segment had four customers who accounted for 20%, 19%, 15%, and 11%, respectively, of its segment revenue.

These segments are monitored separately by management for performance and are consistent with the Partnership's internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the results of each segment.

The following tables set forth our segment financial information for the periods indicated (in thousands):

	December 31, 2016			
	Gathering and Processing	Transmission	Terminals	Total
Sales of natural gas, NGLs and condensate revenue	$153,174	$ 7,775	$ 1	$160,950
Services revenue	10,531	39,196	22,845	72,572
Loss on commodity derivatives, net	(836)	(4)	—	(840)
Total revenue	162,869	46,967	22,846	232,682
Operating expenses:				
Purchases of natural gas, NGL's and condensate	87,026	5,530	—	92,556
Direct operating expenses	41,345	11,920	8,596	61,861
Corporate expenses				54,223
Depreciation, amortization and accretion expense				46,022
Loss on sale of assets, net				591
Loss on impairment of property, plant and equipment				697
Interest expense				15,499
Earnings in unconsolidated affiliates				(40,158)
Income tax expense				2,057
Net income				(666)
Less: Net income attributable to noncontrolling interests				2,804
Net loss attributable to the Partnership				$(3,470)
Segment gross margin (1)	$74,582	$ 41,233	$ 14,250	

(1) Segment gross margin for our Gathering and Processing segment consists of total revenue less construction and operating management agreement income of $1.3 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Transmission segment consists of total revenue less construction and operating management agreement income of less than $0.2 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

	Year Ended December 31, 2015			
	Gathering and Processing	Transmission	Terminals	Total
Sales of natural gas, NGLs and condensate revenue	$170,197	$ 9,600	$ 21	$179,818
Services revenue	3,400	34,082	17,734	55,216
Gain on commodity derivatives, net	1,324	—	—	1,324
Total revenue	174,921	43,682	17,755	236,358
Operating expenses:				
Purchases of natural gas, NGL's and condensate	97,580	8,303	—	105,883
Direct operating expenses	39,249	13,768	7,720	60,737
Corporate expenses				29,818
Depreciation, amortization and accretion expense				38,014
Loss on sale of assets, net				3,011
Loss on impairment of goodwill				118,592
Interest expense				14,745
Earnings in unconsolidated affiliates				(8,201)
Income tax expense				1,134
Loss from discontinued operations, net of tax				80
Net Loss				(127,455)
Less: Net income attributable to noncontrolling interests				25
Net loss attributable to the Partnership				$(127,480)
Segment gross margin (1)	$76,865	$ 35,301	$ 10,035	

(1) Segment gross margin for our Gathering and Processing segment consists of total revenue less unrealized gain on commodity derivatives of $0.3 million, construction and operating management agreement income of $0.8 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Transmission segment consists of total revenue less construction and operating management agreement income of less than $0.1 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

	Year Ended December 31, 2014			
	Gathering and Processing	Transmission	Terminals (b)	Total
Sales of natural gas, NGLs and condensate revenue	$202,035	$ 52,881	$ 109	$255,025
Services revenue	1,581	35,308	15,395	52,284
Gain on commodity derivatives, net	1,091	—	—	1,091
Total revenue	204,707	88,189	15,504	308,400
Operating expenses:				
Purchases of natural gas, NGL's and condensate	152,690	45,262	—	197,952
Direct operating expenses	23,806	15,619	6,494	45,919
Corporate expenses				24,422
Depreciation, amortization and accretion expense				28,832
Loss on impairment of property, plant and equipment				99,892
Loss on sale of assets, net				122
Other expense				670
Interest expense				7,577
Earnings in unconsolidated affiliates				(348)
Income tax expense				557
Loss from discontinued operations, net of tax				611
Net Loss				(97,806)
Less: Net income attributable to noncontrolling interests				214
Net loss attributable to the Partnership				$(98,020)
Segment gross margin (1)	$50,817	$ 42,828	$ 9,010	

(1) Segment gross margin for our Gathering and Processing segment consists of total revenue less unrealized gain on commodity derivatives of $0.4 million, construction and operating management agreement income of $0.8 million, and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Transmission segment consists of total revenue less construction and operating management agreement income of less than $0.1 million and purchases of natural gas, NGLs and condensate.

Segment gross margin for our Terminals segment consists of total revenue less direct operating expenses.

A reconciliation of total assets by segment to the amounts included in the consolidated balance sheets is as follows:

	December 31,	
	2016	2015
Segment assets:		
Gathering and Processing	$537,658	$573,408
Transmission	142,404	133,870
Terminals	45,226	84,449
Other (1)	838,207	100,153
Total assets	$1,563,495	$891,880

(1) Other assets not allocable to segments consist of investment in unconsolidated affiliates, restricted cash and other assets.

22. Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2016 and 2015 are as follows (in thousands, except per unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter (2)
Total revenues	$46,020	$55,382	$63,818	$67,462
Gross margin (1)(3)	27,291	31,809	34,312	36,653
Operating loss	(5,116)	(6,191)	(2,717)	(9,244)
Net income (loss)	(3,964)	(3,591)	2,679	4,210
Net income (loss) attributable to the Partnership	(3,951)	(4,583)	1,483	3,581
General Partner's Interest in net income (loss)	(52)	(61)	19	46
Limited Partners' Interest in net income (loss)	$(3,899)	$(4,522)	$1,464	$3,535
Limited Partners' income (loss) per unit:				
Loss from continuing operations	$(0.33)	$(0.36)	$(0.22)	$(0.20)
Net income (loss)	$(0.33)	$(0.36)	$(0.22)	$(0.20)
Year Ended December 31, 2015				
Total revenues	$64,609	$67,509	$55,641	$48,599
Gross margin (1) (3)	33,776	31,917	28,854	27,654
Operating income (loss)	3,434	1,867	(1,523)	(123,475)
Net income (loss) from continuing operations	835	(2,002)	(4,574)	(121,634)
Income (loss) from discontinued operations, net of tax	5	(31)	(53)	(1)
Net income (loss) attributable to noncontrolling interest	14	32	34	(55)
Net income (loss) attributable to the Partnership	826	(2,065)	(4,661)	(121,580)
General Partner's Interest in net income (loss)	10	(25)	(60)	(1,570)
Limited Partners' Interest in net income (loss)	$816	$(2,040)	$(4,601)	$(120,010)
Limited Partners' income (loss) per unit:				
Loss from continuing operations	$(0.19)	$(0.35)	$(0.48)	$(4.16)
Net loss	$(0.19)	$(0.35)	$(0.48)	$(4.16)

(1) For a definition of gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use gross margin to evaluate our operating performance, please read Item 7. "Management's Discussion and Analysis, How We Evaluate Our Operations."

(2) In the fourth quarter of 2015, we recognized a goodwill impairment charge of $118.6 million.

(3) Amounts are different than previously reported due to reclassifying a portion of equity compensation expense into Direct operating expense for the Terminals segment.

23. Subsequent Event

Distribution

On January 26, 2017, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit for the fourth quarter ended December 31, 2016, or $1.65 per common unit on an annualized basis. The cash distribution was paid on February 13, 2017, to unitholders of record as of the close of business on February 6, 2017.

Dakota Access Connection Agreement

On March 1, 2017, the Partnership announced it has entered a connection agreement with Dakota Access Pipeline ("DAPL"), the 1,172-mile pipeline that extends from the Partnership's Bakken formation production area in North Dakota to Patoka, Illinois. The new DAPL interconnect will tie into the Partnership's Bakken crude oil gathering system which consists of interstate pipelines with capacity to transport up to approximately 40,000 barrels per day of crude oil.

JP Energy Partners

On March 8, 2017, the Partnership completed the acquisition of JPE, an entity controlled by ArcLight affiliates, in a unit-for-unit merger. In connection with the transaction, each JPE common or subordinated unit held by investors not affiliated with ArcLight was converted into the right to receive 0.5775 of a Partnership common unit, and each JPE common or subordinated unit held by ArcLight affiliates was converted into the right to receive 0.5225 of a Partnership common unit. The Partnership issued a total of 20.2 million of its common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates. In connection with the completion of the JPE Merger, the Partnership entered into a supplemental indenture pursuant to which the JPE Entities jointly and severally, fully and unconditionally, guarantee the 8.50% Senior Notes.

As both the Partnership and JPE were controlled by ArcLight affiliates, the acquisition represents a transaction among entities under common control and will be accounted for as a common control transaction. Although the Partnership is the legal acquirer, JPE is considered to be the acquirer for accounting purposes as ArcLight obtained control of JPE prior to obtaining control of the Partnership on April 15, 2013. As a result, JPE will record the acquisition of the Partnership at ArcLight's historical cost basis. The Partnership will file recast historical cost financial statements for the combined entity in May 2017.

Upon the closing of the JPE Merger and the satisfaction of other related conditions the restricted cash proceeds from the 8.50% Senior Notes was released from escrow on March 8, 2017. The Partnership used the net proceeds to repay and terminate JPE's revolving credit facility and to reduce borrowings under the Partnership's Credit Agreement.

JPE owns, operates and develops a diversified portfolio of midstream energy assets with three business segments (i) crude oil pipelines and storage, (ii) refined products terminals and storage and (iii) NGL distribution and sales, which together provide midstream infrastructure solutions for the growing supply of crude oil, refined products and NGLs, in the United States.

Second Amended and Restated Credit Agreement

On March 8, 2017 the Partnership entered into the Second Amended and Restated Credit Agreement, which increased our borrowing capacity from $750 million to $900.0 million and provided for an accordion feature that will permit, subject to the customary conditions, the borrowing capacity under the Credit Agreement to be increased to a maximum of $1.1 billion.