American Midstream Partners, LP
Form 10-K
April 09, 2018

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, 2017
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 check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained 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," "non-accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2017, was $481,090,495. 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, 2017.

There were 52,852,752 common units, 11,009,729 Series A Units and 9,241,642 Series C Units of American Midstream Partners, LP outstanding as of March 26, 2018. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

Documents Incorporated by Reference: None.

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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 Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 of this Annual Report on Form 10-K (the "Annual Report") as well as the following risks and uncertainties:

- our ability to obtain financing required to complete the SXE Merger (as defined herein) or to obtain financing on terms other than those currently anticipated;
- our ability to complete the SXE Transactions (as defined herein) in a timely manner or at all, and to successfully integrate the operations of SXE;
- dispositions of assets owned by us or SXE prior to or following the completion of the SXE Merger, which assets may have been material to us or SXE;
- the outcome of any legal proceedings related to the SXE Merger;
- greater than expected operating costs, customer loss and business disruption following the SXE Merger, including difficulties in maintaining relationships with employees;
- diversion of management time on SXE Transactions-related issues;
- our ability to timely and successfully identify, consummate and integrate our current and future acquisitions (including the SXE Transactions) and complete strategic dispositions, including the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance;
- our ability to maintain compliance with financial covenants and ratios in our revolving credit facility;
- our ability to generate sufficient cash from operations to pay distributions to unitholders;
- 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;
- the demand for natural gas, refined products, condensate or crude oil and NGL products by the petrochemical, refining or other industries;
- the performance of certain of our current and future projects and unconsolidated affiliates that we do not control and disruptions to cash flows from our joint ventures due to operational or other issues that our beyond our control;
- 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;
- security threats such as terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- general economic, market and business conditions, including industry changes and the impact of consolidations and changes in competition;
- the level of creditworthiness of counterparties to transactions;

- the amount of collateral required to be posted from time to time in our 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;
- the timing and extent of changes in natural gas, crude oil, NGLs and other commodity prices, interest rates and demand for our services;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- our dependence on a relatively small number of customers for a significant portion of our gross margin;
- our ability to renew our gathering, processing, transportation and terminal contracts;
- our ability to successfully balance our purchases and sales of natural gas;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects;

- the cost and effectiveness of our remediation efforts with respect to the material weaknesses discussed in Part II, Item 9A - Controls and Procedures of this Annual Report; and
- costs associated with compliance with environmental, health and safety and pipeline regulations;

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 of this Annual Report. Statements in this Annual Report speak as of the date of this Annual 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.

MBbl/d Thousand barrels per day.

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.

Throughput	The volume of natural gas, NGLs, crude oil, and refined products 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 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 five reportable segments, (i) gas gathering and processing services, (ii) liquid pipelines and services, (iii) natural gas transportation services, (iv) offshore pipelines and services and (v) terminalling services, 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 and refined products. As of September 1, 2017, as a result of the disposition of the Propane Marketing Services business ("Propane Business") described in Note 4 - Discontinued Operations, in Part II, Item 8 of this Annual Report, we have eliminated the Propane Marketing Services segment.

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 liquid pipelines, natural gas transportation and offshore pipelines and terminal assets are located in prolific producing regions and key demand markets in Alabama, Arkansas, Louisiana, Mississippi, North Dakota, Texas, Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia. Additionally, we operate a fleet of NGL gathering and transportation trucks in the Eagle Ford shale and the Permian Basin. See Recent Developments for more information about our recent acquisitions and dispositions.

We own or have ownership interests in more than 5,100 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 17 gathering systems, seven interstate pipelines and nine intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 90 MBbl/d of crude oil and 220 MMcf/d of natural gas; six marine terminal sites with approximately 6.7 MMBbls of above-ground aggregate storage capacity for petroleum products, distillates, chemicals and agricultural products; and 90 active transportation trucks and a total trailer fleet of 130, of which 35 are Liquefied Petroleum Gas ("LPG") trailers and 95 are crude oil trailers.

A portion of our cash flow is derived from our investments in unconsolidated affiliates, including a 66.67% operated interest in Destin Pipeline Company, L.L.C. (“Destin”), a natural gas pipeline; a 35.7% non-operated interest in the Class A units of Delta House FPS LLC ("FPS") and of Delta House Oil and Gas Lateral LLC ("Lateral") (collectively referred to herein as "Delta House"), which is a 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 natural gas pipeline; and a 25.3% non-operated interest in Wilprise Pipeline Company, L.L.C. (“Wilprise”), a NGL pipeline.

We manage our business and analyze and report our results of operations through five reportable segments.

• Gas Gathering and Processing Services. Our Gas Gathering and Processing Services segment provides “wellhead-to-market” services to producers of natural gas and NGLs, which include transporting raw natural gas 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.

• Liquid Pipelines and Services. Our Liquid Pipelines and Services segment provides transportation, purchase and sales of crude oil from various receipt points including lease automatic customer transfer (“LACT”) facilities and deliveries to various markets.

• Natural Gas Transportation Services. Our Natural Gas Transportation Services 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.

• Offshore Pipelines and Services. Our Offshore Pipelines and Services segment gathers and transports natural gas and crude oil from various receipt points to other pipeline interconnects, onshore facilities and other delivery points.

• Terminalling Services. Our Terminalling Services 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 and also includes crude oil storage in Cushing, Oklahoma and refined products terminals in Texas and Arkansas.

Recent Developments

In 2017, we completed the following acquisitions and dispositions:

- On March 8, 2017, we completed the acquisition of JP Energy Partners LP (“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. We issued a total of 20.2 million of our common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates.

- On June 2, 2017, we acquired 100% of the Viosca Knoll Gathering System (“VKGS”) from Genesis Energy, L.P. for total consideration of approximately $32 million in cash.

- On August 8, 2017, we acquired 100% of the interest in Panther Offshore Gathering Systems, LLC (“POGS”), Panther Pipeline, LLC (“PPL”) and Panther Operating Company, LLC (“POC” and, together with POGS and PPL, “Panther”) from Panther Asset Management LLC (“Panther Asset Management”) for approximately $60.9 million. The consideration included $39.1 million cash, funded from borrowings under our revolving credit facility, and the issuance of common units, valued at $12.5 million based on unit value as of the acquisition date.

- On September 1, 2017, we completed the disposition of our Propane Business pursuant to the Membership Interest Purchase Agreement dated July 21, 2017, between our wholly-owned subsidiary AMID Merger LP, and SHV Energy N.V.

- On September 29, 2017, we acquired an additional 15.5% equity interest in Class A units of Delta House from affiliates of ArcLight for total cash consideration of approximately $125.4 million.

- On October 27, 2017, our wholly-owned subsidiary, American Midstream Emerald, LLC, entered into a Purchase and Sale Agreement with Emerald Midstream, LLC, an ArcLight affiliate, to purchase an additional 17.0% equity interest in Destin for total consideration of $30.0 million. With the acquisition, we now own a 66.67% interest in

Destin.

- On November 6, 2017, we acquired 100% of the equity interests in Trans-Union Interstate Pipeline, LP ("Trans-Union") from affiliates of ArcLight, for a total consideration of approximately $49.4 million. The consideration consisted of approximately $16.9 million cash funded from borrowings under our revolving credit facility and the assumption of $32.5 million of non-recourse debt.

See Note 3 - Acquisitions, Note 4 - Discontinued Operations and Note 25 - Subsequent Events in Part II, Item 8 of this Annual Report for additional information.

Pending Southcross Energy Partners, L.P. Merger

On October 31, 2017, we, our General Partner, our wholly owned subsidiary, Cherokee Merger Sub LLC (“Merger Sub”), Southcross Energy Partners, L.P. (“SXE”), and Southcross Energy Partners GP, LLC (“SXE GP”), entered into an Agreement and Plan of Merger (the “SXE Merger Agreement”). Upon the terms and subject to the conditions set forth in the SXE Merger Agreement, SXE will merge with Merger Sub (the “SXE Merger”), with SXE continuing its existence under Delaware law as the surviving entity in the SXE Merger and wholly owned subsidiary of us.

At the effective time of the SXE Merger (the “Effective Time”), each common unit of SXE (each, an “SXE Common Unit”) issued and outstanding or deemed issued and outstanding as of immediately prior to the Effective Time will be converted into the right to receive 0.160 (the “Exchange Ratio”) of a common unit (each, an “AMID Common Unit”) representing limited partner interests in us (the “Merger Consideration”), except for those SXE Common Units held by affiliates of SXE and SXE GP, which will be canceled for no consideration. Each SXE Common Unit, Subordinated Unit (as defined in the SXE Merger Agreement) and Class B Convertible Unit (as defined in the SXE Merger Agreement) held by Southcross Holdings LP (“Holdings LP”) or any of its subsidiaries and the SXE Incentive Distribution Rights (as defined in the SXE Merger Agreement) outstanding immediately prior to the Effective Time will be canceled in connection with the closing of the SXE Merger.

In connection with the SXE Merger Agreement, on October 31, 2017, we and our General Partner entered into a Contribution Agreement (the “SXE Contribution Agreement” and, together with the SXE Merger Agreement, the “SXE Transaction Agreements”) with Holdings LP. Upon the terms and subject to the conditions set forth in the SXE Contribution Agreement, Holdings LP will contribute its equity interests in its new wholly owned subsidiary (“SXH Holdings”), which will hold substantially all the current subsidiaries (Southcross Holdings Intermediary LLC, Southcross Holdings Guarantor GP LLC and Southcross Holdings Guarantor LP) and business of Holdings LP, to us and our General Partner in exchange for (i) the number of AMID Common Units with a value equal to $185,697,148, subject to certain adjustments for cash, indebtedness, working capital and transaction expenses contemplated by the SXE Contribution Agreement, divided by $13.69 per AMID Common Unit, (ii) 4,500,000 AMID Preferred Units (as defined in the SXE Contribution Agreement), (iii) options to purchase 4,500,000 AMID Common Units (the “Options”), and (iv) 3,000 AMID GP Class D Units (as defined in the SXE Contribution Agreement) (the transactions contemplated thereby and the agreements ancillary thereto, the “SXE Contribution” and together with the SXE Merger, the “SXE Transactions”). A portion of the consideration will be deposited into escrow in order to secure certain post-closing obligations of Holdings LP. Concurrently with the closing of the transaction, our agreement of limited partnership will be amended to reflect the issuance of AMID Preferred Units, and the GP LLC Agreement will be amended to reflect the issuance of such AMID GP Class D Units.

As disclosed in the Registration statement on Form S-4, as filed with the Securities and Exchange Commission ("SEC") on January 11, 2018, the SXE Merger has a total aggregate consideration of $817.9 million, including a total assumed debt of $644.6 million.

Other developments

In the fourth quarter of 2017, we were notified by the operator of Delta House FPS that certain third party-owned upstream infrastructure would require remedial work, resulting in a temporary delay of production volumes flowing into Delta House. This remediation is scheduled to be completed later in the second quarter of 2018, at which time full production is anticipated to resume flowing into Delta House. This has resulted in a reduction in cash distributions from Delta House, including those attributable to our 35.7% interest, during the curtailment.
On March 11, 2018, we and Magnolia Infrastructure Holdings, LLC ("Magnolia"), an affiliate of ArcLight, entered into a Capital Contribution Agreement to provide additional capital and corporate overhead support to us during the first three quarters of 2018 in connection with temporary curtailment of production flows at Delta House. Pursuant to

the agreement, Magnolia has agreed to provide support to us in an amount to be agreed, up to the difference between the actual cash distribution received by us on account of our interest in Delta House and the quarterly cash distribution expected to be received if production flows to Delta House had not been not curtailed.

On February 16, 2018, we announced the sale of the Refined Products Terminals (the "Refined Products Business") consisting of two terminal facilities, located in Caddo Mills, Texas ("Caddo Mills") and North Little Rock, Arkansas ("NLR"), to DKGP Energy Terminals LLC, a joint venture between Delek Logistics Partners, LP and Green Plains Partners LP, for approximately $138.5 million in cash, subject to working capital adjustments. Closing of the sale of the Refined Products Business is subject to customary closing conditions, including clearance under the Hart-Scott-Rodino Act. The transaction is expected to close in the first half of 2018.

Market Conditions

Average daily prices for New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") crude oil ranged from a high of $66.27 per barrel to a low of $42.48 per barrel from January 1, 2017 through March 26, 2018. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.24 per MMBtu to a low of $2.44 per MMBtu from January 1, 2017 through March 26, 2018.

Fluctuations in energy prices can greatly affect the development of new crude oil and natural gas reserves. Further increases in commodity prices of crude oil and natural gas, as observed through the later part of 2017, could have a positive impact on exploration, development and production activity, and, if sustained, could lead to a material increase in such activity. Sustained expansion or reductions in exploration or production activity in our areas of operation would lead to continued or further increased or 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 commodity prices on our operations.

Business Strategies

Our business objectives continue to focus on maintaining stable cash flows from our existing assets and executing on growth opportunities to increase our long-term cash flows on a per unit basis. 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, the objective of which is to protect against downside risk in our cash flows.

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 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.

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 for the fiscal years ended December 31, 2017 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.

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 several large producers, refiners and marketers.

Significant scale and capability. As of December 31, 2017, after giving effect to the JPE Merger and other acquisitions, we have approximately $1.9 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 5,100 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 17 gathering systems, seven 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 90 MBbl/d of crude oil and 220 MMcf/d of natural gas; six marine terminal sites with approximately 6.7 MMBbls of above-ground storage capacity; and 90 transportation trucks and a total trailer fleet of 130, of which 35 are LPG trailers and 95 are crude oil trailers. 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 indirectly owns 48.6% of our limited partner interests 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 20 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 Segments

AMID manages its business under five distinct operating segments: Gas Gathering and Processing Services, Liquid Pipelines and Services, Natural Gas Transportation Services, Offshore Pipelines and Services and Terminalling Services. Each segment is explained below along with description of the assets that support each of those segments.

Gas Gathering and Processing (G&P) Services Segment

Results of operations from the Gas Gathering and Processing Services segment are determined primarily by the volumes of natural gas 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 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.

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 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 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. See the information set forth in Part II, Item 7A of this Report under the caption - Quantitative and Qualitative Disclosures about Market Risk - Commodity Price Risk.

Our Gas Gathering and Processing Services assets are located in Alabama, Louisiana, Mississippi, 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 Gas Gathering and Processing Services 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, 2017, our fee-based, fixed-margin arrangements and our POP arrangements accounted for approximately 59.1% and 40.9%, respectively, of our segment gross margin for the Gathering and Processing Services segment.

In our G&P segment, we have the following assets:

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.

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, Andrews, and Dawson counties, Texas.

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. Since 2016, the Bazor Ridge facility has been exclusively used as a central gathering and compression facility and processing has been 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 5 MMcf/d. The facility is located near Laurel in Jones County, Mississippi.

Burns Point

Burns Point Plant is 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. The plant has been shut down since December 2017 due to maintenance issues.

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 sixteen 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. Since 2016, the offshore pipe on both systems was abandoned, and the onshore pipe was out of service.

Mesquite

We own a 48.4% non-operated interest in Mesquite, a collaborative arrangement with EnLink Midstream located near Midland, Texas. The Mesquite facility includes a rail terminal 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.

Liquid Pipelines and Services Segment

Results of operations from the Liquid Pipelines and Services segment are determined by the volumes of crude oil transported on the interstate and intrastate pipelines we own. Tariffs associated with our Bakken system are regulated by FERC for volumes gathered via pipeline and trucked to the AMID Truck facility in Watford City, North Dakota. Volumes transported on our Silver Dollar system are underpinned by long-term, fee-based contracts. Our transportation arrangements are further described below:

Firm Transportation Arrangements. Our obligation to provide firm transportation service means that, pursuant to the agreement with the shipper, we transport crude oil 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.

Uncommitted Shipper Arrangements. Our obligation to provide interruptible transportation service means that we are only obligated to transport crude oil 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 or commodity charge for quantities actually shipped.

Fee-Based Arrangements. Under these arrangements our operations are underpinned by long-term, fee-based contracts with leading producers in the Midland Basin. Some of these contracts also have minimum volume commitments as well as some have acreage dedications.

Buy-Sell Arrangements. We enter into outright purchase and sales contracts as well as buy/sell contracts with counterparties, under which contracts we gather and transport different types of crude oil and eventually sell the crude oil to either the same counterparty or different counterparties. We account for such revenue arrangements on a gross basis. Occasionally, we enter into crude oil inventory exchange arrangements with the same counterparty which the purchase and sale of inventory are considered in contemplation of each other. Revenues from such inventory exchange arrangements are recorded on a net basis.

Following are brief descriptions of the assets that make up the Liquid Pipelines and Services segment:

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.

Silver Dollar Pipeline

The Silver Dollar Pipeline is located in the Permian basin and with capacity to transport approximately 130,000 Bbls/d of crude oil. The pipeline was constructed in 2013.

Crude Oil Supply and Logistics (COSL) and AMID Liquids Trucking

Our Marketing business operates around both crude pipeline assets and trucking hubs. We buy and sell crude in North Dakota and Texas to facilitate movements on our pipelines. We operate crude oil trucks in the West Texas, South Texas and the Texas Panhandle. We have a fleet of over 75 crude oil trucks as well as 20 NGL trucks that assist our marketing efforts.

Other Systems

Tri-States, Cayenne and Wilprise are also part of the Liquid Pipelines and Services segment and are listed under Investment in Unconsolidated Affiliates below.

Natural Gas Transportation Services Segment

Results of operations from the Natural Gas Transportation Services segment are determined by a capacity reservation charge from firm transportation contracts, a variable-use or commodity charge for firm and interruptible 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, pursuant to the agreement with the shipper, we 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 or commodity charge with respect to quantities actually transported by us.

Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that, pursuant to the agreement with the shipper, we only 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 or commodity 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.

Following are brief descriptions of the assets that make up the Natural Gas Transportation Services segment:

Midla and MLGT Systems

Our Midla System is a FERC-regulated interstate natural gas pipeline. On April 16, 2015, the FERC approved the Midla Agreement between Midla and its customers allowing Midla to retire the existing 1920's pipeline, which was comprised of approximately 355 miles of pipeline ranging in diameter from two to 22 inches and linked the Monroe Natural Gas Field in northern Louisiana and interconnections with the Transco Pipeline System to customers in Mississippi and Louisiana, and replace the existing natural gas service with a new 52-mile, high pressure 12-inch pipeline (the Midla-Natchez Line) to serve long-standing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line were 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 and service on the Midla-Natchez line began on March 31, 2017. Under the Midla Agreement, Midla executed multiple long-term agreements seeking to recover its investment in the Midla-Natchez Line. As of December 2017, the 1920’s vintage pipeline was inactive.

The Mid Louisiana Gas Transmission LLC (“MLGT”) System is an intrastate transmission system that sources natural gas from interconnects with the Florida Gas Transmission (FGT) Pipeline system, the TETCO Pipeline system, the Transco Pipeline system and the Gulf South Pipeline and delivers to various markets including the city of Baton Rouge utility demand, Louisiana refinery owned and operated by ExxonMobil Corporation, and several other industrial customers. Our MLGT-Baton Rouge System is comprised of approximately 65 miles of pipeline with diameters ranging from three to 16 inches.

The northern portion of the MLGT system, which includes the T-32 lateral that was acquired from Midla in 2017 in conjunction with the FERC approved Midla Agreement, consists of approximately ten miles of high-pressure pipeline with diameters ranging from six to 16 inches. Natural gas on this system is sourced from Tennessee Gas Pipeline and delivered to multiple power plants operated by Entergy. In addition, the ANGUS Chemical facility was connected on the T-32 system in the first half of 2017, increasing the T-32 system load by approximately 7,000 Mcf/d. The entire MLGT System is connected to six receipt and 28 delivery points.

AlaTenn

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, Texas Eastern Pipeline (TETCO), and the Columbia Gulf Pipeline (CGP). In mid-2017, AlaTenn was connected with the Southern Natural Gas (SONAT) which provides access to new markets.

Bamagas

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

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

Magnolia System

The Magnolia system is a Section 311 intrastate pipeline that transports coal-bed methane and receives natural gas from other sources. It is located 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), an interstate pipeline owned by The Williams Companies, Inc. The Magnolia System consists of approximately 118 miles of pipeline and trunk lines ranging from six to 24 inches in diameter and four compressor stations with 4,413 horsepower.

Trans-Union

Trans-Union is a 42-mile, 30-inch diameter high-pressure FERC-regulated natural gas interstate pipeline with 546,000 MMbtu/day of maximum capacity.

Offshore Pipelines and Services Segment

Results of operations from the Offshore Pipelines and Services segment are determined by capacity reservation fees from firm and interruptible 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, pursuant to the agreement with the shipper, we 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, pursuant to the agreement with the shipper, we only 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.

Following are brief descriptions of the assets that make up the Offshore Pipelines and Services segment:

High Point System

The High Point System consists 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 in 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. The system also includes VKGS, which was purchased from Genesis Energy in June 2017. VKGS consists of natural gas gathering and crude oil gathering lines of various diameter sizes as well as the platform at VK817.

American Panther System (AmPan)

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 MMcf/d and crude oil and saltwater capacity of 27.0 MBbl/d.

Main Pass Oil Gathering System (MPOG)

MPOG is 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 our wholly-owned subsidiary, Panther Operating Company, LLC.

Gloria and Lafitte

The Gloria gathering system provides transportation 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 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

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.

Chalmette

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

Other Systems

Delta House, Destin and Okeanos are also part of the Offshore Pipelines and Services segment and are listed under Investments in Unconsolidated Affiliates below.

Terminalling Services Segment

Our Terminalling Services 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, truck weighing, etc. Our firm storage contracts are typically multi-year contracts with renewal options.

Our Terminalling Services 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 and 3.0 million barrels of storage capacity at

Cushing, Oklahoma. Our refined products terminals in North Little Rock, Arkansas and Caddo Mills, TX provide butane blending capabilities.

Following are brief descriptions of the assets that make up the Terminalling Services segment:

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 or railcar. 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. At the Harvey 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. When fully developed, the Harvey Terminal has the potential to provide more than 2 million barrels of storage capacity.

Cushing

Our crude oil storage facility in Cushing, Oklahoma has an aggregate shell capacity of approximately 3.0 million barrels. We generate crude oil storage revenues by charging customers a fixed monthly fee per barrel of shell capacity that is not contingent on the customer's actual usage of our storage tanks, i.e., take-or-pay firm storage contracts.

North Little Rock and Caddo Mills

Our refined products terminals have aggregate storage capacity of approximately 1.3 million barrels at two refined products terminals located in North Little Rock, Arkansas and Caddo Mills, Texas. Our North Little Rock terminal has storage capacity of approximately 550,000 barrels from 11 tanks and is primarily supplied by a refined products pipeline operated by Enterprise TE Products Pipeline Company LLC. Our Caddo Mills terminal has storage capacity of approximately 770,000 barrels from 10 tanks and is primarily supplied by the Explorer Pipeline. We generate fee-based loading revenues with customers under contracts that, consistent with industry practice, typically contain evergreen provisions after an initial term of six months to two years. We also generate revenue from (i) blending activities, such as ethanol blending and butane blending, and (ii) our vapor recovery units. A majority of the customers in our refined products terminals and storage segment are large, well-known oil companies and independent refiners.

On February 16, 2018, we entered into a definitive agreement for the sale of our refined products terminals to DKGP Energy Terminals LLC, a joint venture between Delek Logistics Partners, LP and Greens Plains Partners LP, for approximately $138.5 million in cash, subject to working capital adjustments. Closing of the sale is subject to customary closing conditions, including clearance under the Hart-Scott-Rodino Act. The transaction is expected to close in the first half of 2018.

Investments in Unconsolidated Affiliates

Delta House

On September 29, 2017, we acquired an additional 15.5% equity interest in Class A units of Delta House, from affiliates of ArcLight for total cash consideration of approximately $125.4 million. Post-closing, we and ArcLight indirectly own a 35.7% and 23.3% interest, respectively, in Delta House.

Delta House is a semi-submersible floating production system with associated crude oil and natural gas export pipelines located in the Mississippi Canyon region of the deepwater Gulf of Mexico. The semi-submersible floating production system 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.

Cayenne JV

On August 8, 2017, we entered into a joint venture agreement with Targa Midstream Services, LLC (“Targa”) by which our previously wholly owned subsidiary Cayenne Pipeline, LLC (“Cayenne”) became the Cayenne joint venture between Targa and us (“Cayenne JV”). We received $5.0 million in cash in exchange for the sale of 50% ownership interest in Cayenne to Targa. The sole asset of the joint venture is a natural gas pipeline, which has been converted into a natural gas liquids pipeline. Both parties will each have 50% economic interests and 50% voting rights, with Targa serving as the operator of the pipeline and the joint venture. The additional costs of conversion and associated construction are shared equally by us and Targa. The pipeline became operational on December 28, 2017.

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

On October 27, 2017, American Midstream Emerald, LLC, a wholly-owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement with Emerald Midstream, LLC, an ArcLight affiliate, to purchase an additional 17.0% equity interest in Destin Pipeline Company, LLC for total consideration of $30.0 million. With the acquisition, the Partnership owns a 66.67% interest in Destin. The Destin pipeline is a FERC-regulated, 255-mile natural gas transport 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 midstream business is very competitive, with a number of publicly traded and private equity backed entities servicing the space based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and efficiencies. 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. An increase in competition could result from new pipeline, processing facility, or storage installations or expansions of existing facilities. Major competitors in various aspects of our business include DCP Midstream LLC; Energy Transfer Partners, L.P.; EnLink NGL Marketing, L.P.; Kinder Morgan Energy Partners; Enbridge Energy Partners, L.P.; Columbia Gulf Transmission Company; Enterprise Gas Processing, LLC; Gulf South Pipeline Company, LP; Southern Natural Gas Company; Tennessee Gas Pipeline Company, LLC; Texas Eastern Pipeline; International-Matex Tank Terminals; LBC Tank Terminals; Royal Vopak; Stolt-Nielsen Limited, Westway Terminals Company LLC, and Williams, among others.

Other Segment Information

For additional information on our segments, including revenues from customers, profit or loss and total assets, see Management's Discussion and Analysis of Financial Condition and Results of Operations, in Part II, Item 7 of this Annual Report and Note 23 - Reportable Segments, in Part II, Item 8 of this Annual Report.

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 Natural Gas Act ("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
- 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. On March 15, 2018, FERC issued an order on remand in the United Airlines case and a revised policy statement on income tax recovery that disallows income tax allowances for master limited partnerships in cost of service rates. In addition, FERC issued a notice of proposed rulemaking on March 15, 2018 that proposes to require all interstate natural gas pipelines to submit cost of service information to account for reductions in cost of service resulting from FERC’s new policy on income tax allocations for master limited partnerships and the reduction in the corporate tax rate from the Tax Cuts and Jobs Act that went into effect January 1, 2018. 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. However, we have considered the impact the proposed policy changes by the FERC would have on us, and we have determined that based on the current rate structure on the Partnership's FERC regulated pipelines, the proposed changes are expected to have a negligible impact on the earnings and cash flow of the Partnership. Although we cannot predict whether FERC will propose any additional policy revisions, we expect any such policy revisions will have limited application to us, because a substantial majority of the Partnership's operations are not FERC regulated.

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 FERC'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 FERC issued Order No. 735-A. In Order No. 735-A, the FERC 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 yet issued an order.

Interstate Oil and Liquids Pipeline Regulation

Our Bakken crude oil gathering system, FERC-regulated American Panther, LLC offshore liquids pipelines (known as the Tiger Shoals and MP 77 offshore pipeline systems) and the Tri-States and Wilprise NGL pipelines, in which we have equity investments, are regulated as common carrier interstate pipelines by the FERC under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992 ("EP Act 1992") and the rules and regulations promulgated under those laws. Under the ICA, FERC has authority regarding the rates and terms and conditions of service for the transportation of oil and natural gas liquids in interstate commerce. Such pipelines are regulated as common carriers. FERC regulation is limited to rate-related issues, and does not extend to the construction of new facilities or cessation of service. The ICA and FERC's regulations require that rates and terms and conditions of service for interstate service on common carrier pipelines 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 pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

In general, interstate common carrier pipeline rates are initially set through negotiations with non-affiliated shippers or via cost of service ratemaking. In addition, rates can be set via settlement agreed to by all shippers and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations pursuant to EP Act 1992 establishing an indexing system that permits an oil pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC-approved index, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index in relation to industry costs. On December 17, 2015, the FERC established a new Producer Price Index for Finished Goods (the “PPI-FG”) of PPI-FG plus 1.23 percent for the five-year period beginning July 1, 2016. Under FERC’s regulations, 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.

On March 15, 2018, FERC issued an order on remand in the United Airlines case and a revised policy statement on income tax recovery that disallows income tax allowances for master limited partnerships in cost of service rates. Under the revised policy statement, pipelines can no longer include income tax allowances in their annual FERC Form 6 report regarding their cost of service. In addition, FERC announced in the revised policy statement that it intends to account for its new policy on income tax allowances for MLPs and the reduction in the corporate tax rate from the Tax Cuts and Jobs Act in its next five-year assessment of the oil pipeline index in 2020. However, we have considered the impact the proposed policy changes by the FERC would have on us, and we have determined that based on the current rate structure on the Partnership's FERC regulated pipelines, the proposed changes are expected to have a negligible impact on the earnings and cash flow of the Partnership. Although we cannot predict whether FERC will propose any additional policy revisions, we expect any such policy revisions will have limited application to us, because a substantial majority of the Partnership's operations are not FERC regulated.

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. These persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. 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 (VOC) 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 Subpart OOOO storage tank requirements. On September 23, 2013, the EPA published final revisions to the NSPS Subpart 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 VOC emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA is currently engaged in rulemaking to stay the effective date of these rules. Also, the EPA published NSPS Subpart 0000a, effective August 2, 2016, which places requirements on sources constructed, modified or reconstructed after September 18, 2015. Many of the requirements of NSPS Subpart OOOO mirror those in NSPS Subpart OOOO; however, new equipment being regulated are pneumatic pumps and fugitive emissions at well sites and compressor stations. 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. However, in December 2017, implementation of this rule was delayed until January 2019.

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 VOC 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 as a result of litigation. In January 2018, the Supreme Court ruled that district courts have jurisdiction over challenges to the rule. Litigation surrounding this rule is ongoing, and, in addition to delaying the rule's applicability date until February 6, 2020, the EPA has instituted a rule-making process to repeal 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. As of December 31, 2017, the Partnership is in compliance with the 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

The Partnership does not have any employees. All of the employees required to conduct and support our operations are employed by our General Partner, and the officers of our General Partner manage our operations and activities. As of December 31, 2017, our General Partner employed approximately 490 people who provide direct, full-time support to our operations. 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.

Item 1A. Risk Factors

Limited partner interests 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 our Business

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

As of December 31, 2017, we had approximately $1.2 billion in principal amount of debt outstanding (including approximately $697.9 million of borrowings outstanding under our revolving credit facility). 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 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.

We have identified material weaknesses in our internal controls for 2017 and have been unable to remediate the material weakness identified in 2016. If we fail to remediate these material weaknesses 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.

At December 31, 2016, we identified a material weakness in our internal controls over the level of accounting knowledge, expertise and training commensurate with our financial reporting requirements. This material weakness was not remediated at December 31, 2017. At December 31, 2017, we did not maintain an effective control environment as we lacked sufficient oversight of activities related to our internal control over financial reporting and had an insufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with our financial reporting requirements. This material weakness contributed to additional material weaknesses, as the Partnership did not design and maintain effective controls over: verifying that complex, non-routine transactions were recorded appropriately; all financial statement assertions of revenues and receivables, specifically the review of the accounting for certain contracts, the review that price, volume and other key contractual terms used to record revenue are consistent with the terms of the arrangement and the review that revenue is recorded in the proper period; all financial statement assertions related to acquisitions and divestitures, specifically verifying the existence, rights and obligations associated with assets acquired and liabilities assumed, reviewing the valuation of the purchase price allocation and reviewing the completeness and accuracy of related disclosures; the period-end financial reporting process, specifically the review of account reconciliations and financial statement analyses to support the completeness and accuracy of the consolidated financial statements and disclosures; and the accuracy and valuation of asset retirement obligations, goodwill, other intangible assets and finite-lived assets, specifically the review of the model, data, assumptions and calculations used in determining the estimated asset retirement obligation and in impairment tests, and the related identification of changes in events and circumstances that indicate it is more likely than not that an impairment indicator has occurred. Additionally, we did not maintain effective controls over certain information technology ("IT") general controls for a significant application used in the preparation of our financial statements. Specifically, we did not maintain user access controls to ensure appropriate segregation of duties and adequate restriction of user and privileged access to the financial application, programs, and data to appropriate Partnership personnel. These IT deficiencies did not result in a material misstatement to the financial statements, however, the deficiencies, when aggregated, could impact our ability to maintain effective segregation of duties, as well as maintain effective IT-dependent controls which could result in misstatements of substantially all of the financial statement accounts and disclosures resulting in a material misstatement to the annual or interim consolidated financial statements that otherwise would not be prevented or detected. Accordingly, our management determined that, as of December 31, 2017, our disclosure controls and procedures and our internal control over financial reporting were not effective. The specific material weaknesses and our remediation efforts are described in Item 9A, Controls and Procedures of this Annual Report. 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 will not be prevented or detected on a timely basis. We were not able to remediate material weaknesses identified at December 31, 2016 during 2017, and we cannot assure you that we will adequately remediate the material weaknesses or that additional material weaknesses in our internal controls will not be identified in the future.

We are in the process of remediating the identified material weaknesses 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 weaknesses 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 these material weaknesses or modify certain of the remediation measures. 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 indenture governing our senior 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;
- make certain investments and acquisitions;
- redeem or repay other debt or make other restricted payments;
- enter into certain types of transactions with affiliates;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- 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;

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Our Second Amended and Restated Credit Agreement (the "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 (except during a specified acquisition period, as determined under the terms of the Credit Agreement, at which time such ratio is increased to 5.50 times adjusted consolidated EBITDA), (ii) a consolidated secured leverage ratio that requires our secured indebtedness not to exceed 3.50 times adjusted consolidated EBITDA, and (iii) 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 $900.0 million. As of December 31, 2017, our consolidated total leverage ratio was 5.23, our secured leverage ratio was 3.29 and our interest coverage ratio was 3.62, which were in compliance with the financial covenants. 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.

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 and our joint ventures gather, process and transport, and related revenues earned under our and our joint ventures' transportation contracts;
- 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;
- capacity charges and volumetric fees associated with our transportation services;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating, maintenance and corporate costs; and
- 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.

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.

Any decrease in the volumes of natural gas, NGLs or crude oil that we or our joint ventures gather, process or transport could adversely affect our business and operating results.

The 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, 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;
- the absence of operational issues that curtail production; and
- the availability of drilling rigs and other production and development costs.

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 decreased or if producers experienced sustained curtailment of production, 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 and crude oil prices declined dramatically in late 2015 and have fluctuated throughout 2016 and 2017. 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 and 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, crude oil and liquefied natural gas, or LNG;
- the availability of transportation systems with adequate capacity;

- the volatility and uncertainty of regional pricing differentials;
- 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.

Our growth strategy, and ability to fund expansion capital projects, requires access to new capital. Our ability to access the capital markets, 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. The delayed filing of this Annual Report has made us currently ineligible to use a registration statement on Form S-3 to register the offer and sale of securities, which could increase the expense of accessing the capital markets. 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 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.

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 MPOG system and non-operated interests 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 and weather derivatives 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.

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 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 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 low commodity price environment in prior years 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, and this could recur. 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 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. 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.
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.

Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) in 2010. Among other things, the Dodd-Frank Act mandated significant changes to the over-the-counter derivative market and requires the Commodities Futures Trading Commission (the “CFTC”), the SEC and other regulators to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivative market. Although as of December 31, 2017, the rules and regulations under the Dodd-Frank Act have not had an adverse effect on our ability to use certain derivative instruments, such rules and regulations may have an adverse effect on our ability to do so in the future.

The rulemaking process under the Dodd-Frank Act has not been fully completed. As a result, the full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Dodd-Frank Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize and restructure our existing derivatives contracts, impact commodity prices and affect the number or creditworthiness of available counterparties. For example, the rules and regulations under the Dodd-Frank Act may increase the costs of certain derivative products as a result of the imposition of capital, margin, clearing and exchange-trading requirements either on us or on our counterparties. Any requirement to post more collateral to our counterparties in excess of what we currently post to collateralize our obligations may have a negative impact upon our liquidity. Further, the CFTC has proposed rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions which, if finalized, could further restrict our ability to utilize these products. If, as a result of the Dodd-Frank Act and the rules and regulations promulgated thereunder, we reduce our use of certain derivatives, 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 or increase our distributions.
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 50% membership interest in Cayenne, 35.7% of the Class A units of Delta House FPS LLC and Delta House Oil and Gas Lateral LLC, a 25.3% membership interest in Wilprise, and a 16.7% membership interest in Tri-States. We do not control these projects or joint ventures or their governing boards. As a result, our ability to pay cash distributions to our unitholders will depend in part on factors beyond our control, such as the performance of these projects or joint ventures and their distributions of cash to us. Cash distributions to us may be reduced or suspended if the assets comprising the businesses of these projects or joint ventures, or the assets of their customers, are adversely impacted by operational hazards.

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. 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.

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. 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 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. However, the EPA is currently engaged in rulemaking to stay the effective date of these rules. 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. In December 2017, implementation of this rule was delayed until January 2019. 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. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. 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 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 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. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their greenhouse gas emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the company's causation of or contribution to the asserted damage, or to other mitigating factors.

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 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 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 million during 2018 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.

A downgrade in our credit ratings could impact our access to capital and costs of doing business, and maintaining credit ratings is under the control of independent third parties.
Rating agencies may reevaluate our ratings, and any additional actual or anticipated downgrades in such credit ratings could limit our ability to access credit and capital markets, including to finance the SXE Transactions, or to restructure or refinance our indebtedness. On November 1, 2017, S&P and Moody's both announced that our long term credit rating had been placed on watch as a result of the announcement of the SXE Transactions. As a result of any potential downgrades, future financing or refinancing, including to finance the SXE Transactions, may result in higher borrowing costs and require more restrictive terms and covenants, including obligations to post collateral with third parties, which may further restrict our operations and negatively impact liquidity.
Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.
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, including the availability of skilled labor, equipment and materials to complete expansion projects and potential changes in federal, state and local statutes and regulations, including environmental requirements, that may delay or prevent a project from proceeding or increase the anticipated cost of the project. 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.
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 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, Trans-Union and Midla interstate natural gas transportation systems, our Destin pipeline, which we operate and own 66.7%, 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
- 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. Under the EP Act 2005, 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. The current maximum daily penalty for a violation is $1,238,271.

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, FERC-regulated American Panther, LLC offshore liquids pipelines (known as the Tiger Shoals and MP 77 offshore pipeline systems) and the Tri-States and Wilprise NGL pipelines, in which we have equity investments, 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 FERC’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 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. On March 15, 2018, FERC issued an order on remand in the United Airlines case and a revised policy statement on income tax recovery that disallows income tax allowances for master limited partnerships in cost of service rates. In addition, FERC issued a notice of proposed rulemaking on March 15, 2018 that proposes to require all interstate natural gas pipelines to submit cost of service information to account for reductions in cost of service resulting from FERC’s new policy on income tax allocations for master limited partnerships and the reduction in the corporate tax rate from the Tax Cuts and Jobs Act that went into effect January 1, 2018. As a result of this new policy and proposed rule, 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. However, we have considered the impact the proposed policy changes by the FERC would have on us, and we have determined that based on the current rate structure on the Partnership's FERC regulated pipelines, the proposed changes are expected to have a negligible impact on the earnings and cash flow of the Partnership. Although we cannot predict whether FERC will propose any additional policy revisions, we expect any such policy revisions will have limited application to us, because a substantial majority of the Partnership's operations are not FERC regulated.

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 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. See “Business - Environmental Matters - Air Quality and Climate Control” in Item 1 of this Annual Report 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. See “Business - Environmental Matters” in Item 1 of this Annual Report 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.

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 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 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. As of December 31, 2017, we did not maintain effective controls over certain information technology general controls for a significant application used in the preparation of our financial statements. Any future cyber security attacks that affect our facilities, our customers and any financial data, including as a result of our inability to adequately restrict user and privileged access to our financial application, programs and data, could have a material adverse effect on our business. In addition, cyber-attacks on our financial, customer and employee data may result in financial loss and may negatively impact our reputation. We may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security, and additional security personnel. 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 and the threat of terrorist attacks 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 terrorist attacks in the U.S. 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 the SXE Transactions

We may be unable to obtain the regulatory clearances required to complete the SXE Merger or, in order to do so, we may be required to comply with material restrictions or satisfy material conditions.

AMID and SXE received early termination of the applicable waiting period under the HSR Act on December 8, 2017. The Merger may still be reviewed under antitrust statutes of other governmental authorities, including by state regulatory authorities such as the MPSC. The closing of the SXE Merger is subject to the condition that there is no law, injunction, judgment or ruling by a governmental authority in effect enjoining, restraining, preventing or prohibiting the SXE Merger. We can provide no assurance that all required regulatory clearances will be obtained. If a governmental authority asserts objections to the SXE Merger, we may be required to divest assets in order to obtain antitrust clearance. There can be no assurance as to the cost, scope or impact of the actions that may be required to obtain antitrust or other regulatory approval. If we take such actions, it could be detrimental to it or to the combined organization following the consummation of the SXE Merger. Furthermore, these actions could have the effect of delaying or preventing completion of the SXE Merger or imposing additional costs on or limiting the revenues or cash available for distribution of the combined organization following the consummation of the SXE Merger.

State attorneys general could seek to block or challenge the SXE Merger as they deem necessary or desirable in the public interest at any time, including after completion of the transaction. In addition, in some circumstances, a third party could initiate a private action under antitrust laws challenging or seeking to enjoin the SXE Merger, before or after it is completed. We may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

The MPSC requires that when a company proposes a change of control of a certificate of public convenience and necessity (“CPCN”), the company must obtain an order from the MPSC approving the sale and transfer of the CPCN. Southcross Mississippi Industrial Gas Sales, L.P. (“Southcross Mississippi”), an indirect subsidiary of SXE, has a CPCN that, subject to the approval of the MPSC, will be transferred in connection with the SXE Transactions. The MPSC could decide not to issue an order authorizing the transfer of the CPCN. Moreover, there is no guarantee that, if granted, such order will be granted in a timely manner or will be free from potentially burdensome conditions.

We may have difficulty attracting, motivating and retaining employees in light of the SXE Merger.

Uncertainty about the effect of the SXE Merger on our employees may have an adverse effect on the combined organization. This uncertainty may impair our ability to attract, retain and motivate personnel until the SXE Merger is completed. Employee retention may be particularly challenging during the pendency of the SXE Merger, as employees may feel uncertain about their future roles with the combined organization. If employees 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 SXE Merger could be reduced.

We are subject to business uncertainties and contractual restrictions while the SXE Transactions are pending, which could adversely affect our business and operations.

In connection with the pending SXE Transactions, it is possible that some customers, suppliers and other persons with whom we have business relationships may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship with us as a result of the SXE Transactions, which could negatively affect our revenues, earnings and cash available for distribution, as well as the market price of AMID Common Units, regardless of whether the SXE Transactions completed.

Under the terms of the Merger Agreement, we are subject to certain restrictions on the conduct of our business prior to completing the SXE Merger, which may adversely affect our ability to execute certain of our business strategies. Such limitations could negatively affect our business and operations prior to the completion of the SXE Merger. Furthermore, the process of planning to integrate two businesses and organizations for the post-merger period can divert management attention and resources and could ultimately have an adverse effect on each party.

However, we are permitted to engage in certain activities and transactions prior to completion of the SXE Merger, such as certain financings, incurrence of indebtedness, issuances of equity, sales of assets and acquisitions. Any of these transactions could affect our current and future financial and operating results and of the combined company.

The SXE Merger is subject to conditions, including certain conditions that may not be satisfied on a timely basis, if at all. Failure to complete the SXE Merger, or significant delays in completing the SXE Merger, could negatively affect the trading price of AMID Common Units and our future business and financial results.

The completion of the SXE Merger is subject to a number of conditions. The completion of the SXE Merger is not assured and is subject to risks, including the risk that approval of the SXE Merger by SXE Unitholders or by governmental agencies is not obtained or that other closing conditions are not satisfied. If the SXE Merger is not completed, or if there are significant delays in completing the SXE Merger, the trading price of AMID Common Units and our future business and financial results could be negatively affected, and we will be subject to several risks, including the following:

- we may be liable for damages to SXE under the terms and conditions of the Merger Agreement;
- negative reactions from the financial markets, including declines in the price of AMID Common Units due to the fact that current prices may reflect a market assumption that the SXE Merger will be completed; and
- the attention of our management will have been diverted to the SXE Merger rather than our own operations and pursuit of other opportunities that could have been beneficial to us.

The SXE Merger will not occur if the conditions to closing the SXE Contribution under the SXE Contribution Agreement, including the refinancing by us of SXE's indebtedness, are not satisfied and the closing of the SXE Contribution does not occur or if the SXE Contribution Agreement is otherwise terminated.

It is a condition to the closing of the SXE Merger under the terms of the SXE Merger Agreement that the SXE Contribution will have closed in accordance with the SXE Contribution Agreement. Additionally, the SXE Merger Agreement will terminate automatically, and the SXE Merger will not occur, if the SXE Contribution Agreement is terminated. The completion of the SXE Contribution is subject to a number of conditions, is not assured and is subject to risks, including the risk that approval by governmental agencies is not obtained or that other closing conditions are not satisfied. Additionally, if we have not obtained sufficient financing to make the cash payments required to be made at the closing of the SXE Contribution, including for the refinancing of SXE's indebtedness, we may be required under certain circumstances to pay a reverse termination fee of $17 million to Holdings LP. We do not have in place committed financing sufficient to make the payments at the closing of the SXE Contribution, and there can be no assurances that we will be able to obtain such financing on acceptable terms or at all. Any such failure to obtain financing would likely result in the termination of the SXE Contribution Agreement and SXE Merger Agreement and the failure to complete the SXE Merger.

The number of outstanding AMID Common Units will increase as a result of the SXE Transactions, which could make it more difficult for us to pay our current level of quarterly distributions.

As of December 31, 2017, there were approximately 52.7 million AMID Common Units outstanding. We estimate that we will issue approximately 3.5 million AMID Common Units in connection with the SXE Merger and 13.6

million AMID Common Units in connection with the Contribution. Accordingly, the aggregate dollar amount required to pay the current per unit quarterly distribution on all AMID Common Units will increase, which could increase the likelihood that we will not have sufficient funds to pay the current level of quarterly distributions to all AMID Common Unitholders. Using a $0.4125 per AMID Common Unit distribution (the distribution AMID had declared with respect to the fourth fiscal quarter of 2017 paid on February 14, 2018 to holders of record as of February 7, 2018) the aggregate cash distribution paid to AMID Common Unitholders totaled approximately $21.7 million, including a distribution to AMID GP in respect of its general partner interest. The combined pro forma AMID distribution with respect to the fourth fiscal quarter of 2017, had the SXE Merger been completed prior to such distribution, would have resulted in $0.4125 per unit being distributed on approximately 69.8 million AMID Common Units, or a total of approximately $29.1 million including a distribution of $0.3 million to AMID GP in respect of its general partner interest. As a result, we would have been required to distribute an additional $7.4 million in order to maintain the distribution level of $0.4125 per AMID Common Unit payable with respect to the fourth fiscal quarter of 2017.

A substantial number of AMID Common Units and other securities convertible into, or exercisable for, AMID Common Units, will be issued in connection with the SXE Transactions, which will dilute the ownership interests of existing unitholders, or may otherwise reduce the value of AMID Common Units.

Upon the terms and subject to the conditions set forth in the SXE Merger Agreement, at the Effective Time, each SXE Common Unit issued and outstanding as of immediately prior to the Effective Time will be converted into the right to receive 0.160 of an AMID Common Unit. In addition, upon the terms and subject to the conditions set forth in the Contribution Agreement, Holdings LP will receive AMID Common Units, Series E preferred units, which will be convertible into AMID Common Units, and the Options, which will be exercisable into AMID Common Units. The issuance of AMID Common Units in the Transaction and the issuance of AMID Common Units upon conversion of the Series E preferred units or the exercise of the Options issued in the SXE Contribution will dilute the ownership interests of existing unitholders.

While Holdings LP has agreed not to sell any AMID Common Units, or any other securities convertible into, or exercisable for, AMID Common Units, for a specified period set forth in the SXE Contribution Agreement, any sales, or expectation of sales, in the public market of AMID Common Units, including those issuable upon the conversion of the Series E preferred units or the exercise of the Options, after the expiration of such period could adversely affect prevailing market prices of AMID Common Units.

We will incur substantial transaction-related costs in connection with the SXE Transactions.

We expect to incur a number of non-recurring transaction-related costs associated with completing the SXE Transactions, combining the operations of the acquired organizations and achieving desired synergies. These fees and costs will be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to financial, legal and accounting advisors, filing fees and printing costs. Additional unanticipated costs may be incurred in the integration of the our business with the business of SXE and the other businesses acquired from Holdings LP. 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.

Failure to successfully combine our business with the business of SXE and the other businesses acquired from Holdings LP in the expected time frame may adversely affect the future results of the combined organization, and, consequently, the value of our common units.

The success of the SXE Merger will depend, in part, on our ability to realize the anticipated benefits and synergies from combining our business with the business of SXE and the other businesses acquired from Holdings LP. To realize these anticipated benefits, the businesses must be successfully combined. If the combined organization is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the SXE Merger may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the SXE Merger. These integration difficulties could result in declines in the market value of our common units.

Risks Related to Our Units, Partnership Structure and Ownership

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 Fifth Amended and Restated Agreement of Limited Partnership (as amended, the “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;
- 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;
- 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; and

- although ArcLight has provided cash and other support for our liquidity in the past, it is under no obligation to do so in the future.

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. Although ArcLight has provided us with financial support in the past, it is under no obligation to do so in the future. 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 Partnership Agreement limits our General Partner's fiduciary duties to us and the holders of our common units and 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 eliminate and replace the fiduciary duties to which our General Partner would otherwise be held by 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 and AMID GP Holdings, LLC ("AMID GP Holdings"). 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 interests voting together as a single class is required to remove our General Partner. As of December 31, 2017, ArcLight indirectly held common units or convertible preferred units representing 48.60% of our then-outstanding common units (on an as converted basis).

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 or AMID GP Holdings to transfer all or a portion of their ownership interests 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, including units that are senior to the common units and pari passu with our existing convertible preferred 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 convertible preferred 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 26, 2018, ArcLight held all of our Series A-1 Units, Series A-2 Units and Series C Units through its affiliates. The Series A-1, A-2 and C are all convertible into common units at the election of ArcLight at any time. The sale of these units and the common units owned directly and indirectly by ArcLight and its affiliates 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 35.7% 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 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”) were to treat 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.

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 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 21%, 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. We believe the income that we treat as qualifying satisfies the

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requirements under these regulations. However, there are no assurances that the regulations will not be revised to take a position that is contrary to our interpretation of current law.

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. 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.

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. Although our General Partner may elect to have our unitholders and former unitholders take such audit adjustments into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. If we are unable to have the unitholders take such audit adjustment into account in accordance with their interests during the taxable year under audit, the current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units during the taxable year under audit. 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.

Unitholders may be subject to limitations on their ability to deduct interest expense we incur.

Our ability to deduct business interest expense will be limited for U.S. federal income tax purposes to an amount equal to the sum of (i) our business interest income during the taxable year and (ii) 30% of our adjusted taxable income for such taxable year. For the purposes of this limitation, adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. If we are not entitled to fully deduct our business interest in any taxable year, such excess business interest expense will be allocated to each unitholder as excess business interest and can be carried forward by the unitholder to successive taxable years and used to offset any excess taxable income allocated by us to such unitholder. Any excess business interest expense allocated to a unitholder will reduce such unitholder’s tax basis in its partnership interest in the year of the allocation even if the expense does not give rise to a deduction to the unitholder in that year. Immediately prior to a disposition of its shares, a unitholder’s tax basis will be increased by the amount by which such basis reduction exceeds the excess interest expense that has been deducted by such unitholder.

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.

Further, in addition to the other limitations described above, non-corporate taxpayers may only deduct business losses up the gross income or gain attributable to such trade or business plus $250,000 ($500,000 for unitholders filing jointly). Amounts that may not be deducted in a taxable year may be carried forward into the following taxable year. This limitation shall be applied after the passive loss limitations and, unless amended, applies only to taxable years beginning prior to December 31, 2025.

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. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. persons are generally taxed and subject to U.S. federal income tax filing requirements on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and, under recently enacted legislation, any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate, and a non-U.S. unitholder who sells or otherwise disposes of its interest will be subject to U.S. federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the non-U.S. unitholder.

Recently enacted legislation also imposes a federal income tax withholding obligation of 10% of the amount realized upon a non-U.S. person's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the application of this withholding rule to dispositions of publicly traded partnership interests has been temporarily suspended by the IRS until regulations or other guidance that resolves the challenges have been issued. It is not clear if or when such regulations or guidance will be issued. Non-U.S. persons 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.

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.

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 unit holder'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

None

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. We believe that our existing facilities are adequate to meet our needs for the immediate future and that additional facilities will be available on commercially reasonable terms as needed.

Item 3. Legal Proceedings

On December 18, 2015, Vintage Assets, Inc., et al. (“Vintage”), filed a lawsuit in the Judicial District Court in Plaquemines Parish, Louisiana alleging that defendants Southern Natural Gas Company, L.L.C. (“SNG”) and Tennessee Gas Pipeline Company, L.L.C. failed to maintain the canals in which their pipelines were laid and failed to maintain the associated banks causing erosion, ecological damage, and unspecified monetary damages, and trespassed on Plaintiffs’ property. The case was removed to the United States District Court for the Eastern District of Louisiana on January 27, 2016. Our subsidiaries High Point Gas Transmission, L.L.C. (“HPGT”) and High Point Gas Gathering, L.L.C. (“HPGG”) are successors in interest to SNG with regard to certain of the property interests at issue in this proceeding. On October 24, 2016, HPGT and HPGG were added to the lawsuit as co-defendants. Plaintiffs subsequently demanded either restoration of their property or, alternatively, $44.0 million in damages (the plaintiff’s alleged estimated cost of restoration). A bench trial was held in September 2017, but a judgment has not been rendered. The purchase and sale agreements pursuant to which HPGG and HPGT acquired its property interests contain provisions pursuant to which the sellers agreed to indemnify HPGT or HPGG, as applicable, from all liabilities, including attorney’s fees, attributable to the period prior to such acquisition.

While the ultimate impact of any proceedings cannot be predicted with certainty, our management believes that the resolution of any of our pending proceedings 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 2017 and 2016, together with distributions declared for that quarter through December 31, 2017:

Period Ended	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
High Price	$18.45	$15.25	$15.00	$14.75
Low Price	$14.20	$11.10	$12.35	$11.65
Distribution per common unit	$0.4125	$0.4125	$0.4125	$0.4125
2016				
High Price	$8.49	$14.00	$15.19	$18.30
Low Price	$4.03	$6.18	$10.39	$13.06
Distribution per common unit(1)	$0.7375	$0.7375	$0.7375	$0.7375

(1) Recast to reflect both AMID and JPE quarterly distributions.

Unitholder Matters

As of March 26, 2018, there were 127 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. As of March 26, 2018 we have approximately 11,009,729 Series A Units, 9,241,642 Series C Units and 964,563 General Partner units. 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, Series A Units and Series C Units. If the SXE Transactions are consummated, we will issue a new class of preferred units called Series E preferred units at the closing of the SXE Transactions pursuant to the SXE Transaction Agreements.

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 quarterly a cash dividend to those unitholders of record on the applicable record date, as determined by the General Partner.

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.

The following table sets forth the number of units outstanding at December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Series A convertible preferred units	10,719	10,107
Series C convertible preferred units	8,965	8,792
Series D convertible preferred units [1]	—	2,333
Limited partner common units	52,711	51,351
General Partner units	965	680

(1) Series D convertible preferred units ("Series D Units") were redeemed as of October 2, 2017.

General Partner Units

Our General Partner's initial 2.0% interest in distributions has been reduced to 1.32% as of December 31, 2017 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.

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 since the distribution for the three months ended June 30, 2014. At December 31, 2017, we accrued $4.4 million of contractual paid-in-kind distributions on the Series A Units which were distributed on February 14, 2018.

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 and upon the consent of the holders of the Series C Units. At December 31, 2017, we accrued $3.7 million of contractual paid-in-kind distributions on the Series C Units which were distributed on February 14, 2018.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans, LTIP and Assumed LTIP:

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))
LTIP			
Restricted units (phantom units)	1,397,634		
Performance units	524,000		
Options	245,000	$ 8.50	
Total	2,166,634		4,134,412
Assumed LTIP			
Phantom units	10,344		151,845
Total AMID	2,176,978		4,286,257

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 2017, 2016, and 2015 begin on page F-1 to this Annual Report.

On March 8, 2017 we acquired JPE in a unit-for-unit exchange. As both the Partnership and JPE were controlled by ArcLight, the acquisition represents a transaction among entities under common control and is accounted for as a common control transaction in a manner similar to a pooling of interests. Although the Partnership is the legal acquirer, JPE is considered to be the acquirer for accounting purposes as ArcLight obtained control of JPE before it obtained control the Partnership. The following selected historical financial information represent JPE's historical cost basis financial information which has been recast to reflect the acquisition of the Partnership at ArcLight's historical cost basis effective April 15, 2013, the date on which ArcLight obtained control of the Partnership.

On September 1, 2017, the Partnership completed the disposition of its Propane Business. Through the transaction, the Partnership divested 100% of the Propane Business, including Pinnacle Propane's 40 service locations; Pinnacle Propane Express' cylinder exchange business and related logistic assets; and the Alliant Gas utility system. In connection with the transaction, the Partnership received $170.0 million in cash and recorded a gain on the sale of $47.4 million, net of $2.5 million transaction costs. As a result of the disposition of the Propane Business, the Partnership has classified the accounts and the results of operations of the Propane Business as discontinued operations for all periods.

For a detailed discussion of the following table, see Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations.

	Years ended December 31,				
	2017 (1)	2016 (2)	2015 (2)	2014 (2)	2013 (2)
	(in thousands, except per unit and operating data)				
Statements of Operations Data:					
Revenues:					
Total operating revenue	$651,435	$589,026	$750,304	$838,949	$436,021
Operating expenses:					
Cost of sales	457,371	393,351	567,682	672,948	331,831
Direct operating expenses	82,256	71,544	71,729	58,048	33,962
Corporate expenses	112,058	89,438	65,327	60,465	51,193
Depreciation, amortization and accretion	103,448	90,882	81,335	57,818	43,458
Loss (gain) on sale of assets, net	(4,063)	688	2,860	4,087	(17)
Impairment of long-lived assets / intangible assets	116,609	697	—	21,344	8,830
Impairment of goodwill	77,961	2,654	148,488	—	—
Total operating expenses	945,640	649,254	937,421	874,710	469,257
Operating loss	(294,205)	(60,228)	(187,117)	(35,761)	(33,236)
Other income (expense):					
Interest expense	(66,465)	(21,433)	(20,077)	(16,497)	(15,418)
Other income (expense)	36,254	254	1,460	(1,096)	544
Loss on extinguishment of debt	—	—	—	(1,634)	—
Earnings in unconsolidated affiliates	63,050	40,158	8,201	348	—
Loss from continuing operations before income taxes	(261,366)	(41,249)	(197,533)	(54,640)	(48,110)
Income tax (expense) benefit	(1,235)	(2,580)	(1,885)	(856)	212
Loss from continuing operations	(262,601)	(43,829)	(199,418)	(55,496)	(47,898)
Discontinued operations:					
Income (loss) from discontinued operations, net of tax	44,095	(4,715)	(423)	(24,071)	13,446
Net loss	(218,506)	(48,544)	(199,841)	(79,567)	(34,452)
Net income (loss) attributable to non-controlling interests	4,473	2,766	(13)	3,993	705
Net loss attributable to the Partnership	$(222,979)	$(51,310)	$(199,828)	$(83,560)	$(35,157)
General Partner's Interest in net loss	$(2,981)	$(233)	$(1,823)	$(398)	$(864)
Limited Partners' Interest in net loss	$(219,998)	$(51,077)	$(198,005)	$(83,162)	$(34,293)
Limited Partners' net (loss) per common unit:					
Basic and diluted:					
Loss from continuing operations	$(5.70)	$(1.51)	$(4.91)	$(2.77)	$(3.21)
Income (loss) from discontinued operations	0.85	(0.09)	(0.01)	(0.52)	(0.07)

Net loss	$(4.85)	$(1.60)	$(4.92)	$(3.29)	$(3.28)
Weighted average number of common units outstanding:					
Basic and diluted (3)	52,043	51,176	45,050	27,524	18,931
Statement of Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$14,986	$90,639	$86,978	$51,635	$29,500
Investing activities	252,310	(564,504)	(250,771)	(518,023)	(115,173)
Financing activities	(264,180)	477,544	161,956	466,577	79,156
Other Financial Data:					
Adjusted EBITDA (4)	$176,394	$177,565	$100,721	$74,286	$63,707
Total segment gross margin (5)	242,084	223,635	179,856	153,524	96,809
Distribution declared per common unit	$1.65	$1.99	$2.14	$1.85	$1.75
Segment gross margin:					
Gas Gathering and Processing Services	49,010	48,245	65,692	51,213	5,673
Liquid Pipelines and Services	27,999	31,556	26,399	25,038	5,420
Natural Gas Transportation Services	23,424	18,616	18,073	13,691	13,150
Offshore Pipelines and Services	103,664	82,346	33,613	29,089	36,318
Terminalling Services	37,987	42,872	36,079	34,493	36,248
Balance Sheet Data (at period end):					
Cash and cash equivalents	$8,782	$5,666	$1,987	$3,824	$3,627
Accounts receivable and unbilled revenue	98,132	67,625	61,016	116,676	129,724
Property, plant and equipment, net	1,095,585	1,066,608	981,321	887,045	537,304
Total assets	1,923,466	2,349,321	1,751,889	1,865,210	1,292,695
Current portion of long-term debt	7,551	5,438	2,758	3,141	3,141
Long-term debt	1,201,456	1,235,538	687,100	456,965	314,764
Operating Data:					
Gas Gathering and Processing Services:					
Average throughput (MMcf/d)	202.0	220.6	240.0	155.8	129.5
Liquid Pipelines and Services:					
Average throughput Pipeline (Bbl/d)	34,248	32,257	34,946	20,868	13,738
Average throughput Truck (Bbl/d)	2,910	1,628	—	—	—
Natural Gas Transportation Services:					
Average throughput (MMcf/d)	420.4	389.9	364.1	373.3	364.9
Offshore Pipelines and Services:					
Average throughput (MMcf/d)	309.6	466.4	442.8	524.6	498.9
Terminalling Services:					
Storage Capacity (Bbls)	4,957,328	5,011,133	4,487,542	4,247,058	4,114,792
Design Capacity (Bbls)	5,400,800	5,173,717	4,688,950	4,363,817	4,165,600
Storage utilization	91.8 %	96.9 %	95.7 %	97.3 %	99.0 %
Terminalling and Storage throughput (Bbls/d)	58,670	56,741	62,075	63,859	69,071

The following transactions affect comparability between years:

(1) i) In June 2017, we acquired a 100% interest in VKGS which was accounted for as a business combination and was included in our Offshore Pipelines and Services segment; ii) in August 2017, we acquired a 100% interest in POGS; the outstanding interests in one of our equity investments, MPOG, which was accounted for as a change in control and has been consolidated from the acquisition date; and the remaining equity interest in our consolidated

subsidiary, AmPan, each of which were included in our Offshore Pipelines and Services segment; iii) in September 2017, we acquired an additional 15.5% equity

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interest in Delta House Class A units, which we accounted for as an equity method investment and was included in our Offshore Pipelines and Services segment; iv) in October 2017, we acquired an additional 17.0% membership interest in Destin which we accounted for as an equity method investment and was included in our Liquid Pipelines and Services segment and v) in November 2017, we acquired 100% of the equity interest in Trans-Union which represented an asset acquisition among entities under common control and was included in our Natural Gas Transportation Services segment.

(2) i) In October 2016 and April 2016, we acquired 6.2% and a 1% non-operated interests in Delta House Class A units, which we accounted for as equity method investments and were included in our Offshore Pipelines and Services segment; 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 accounted for as equity method investments and were included in our Liquid Pipelines and Services and Offshore Pipelines and Services segments; iii) in April 2016 we acquired a 60% interest in Ampan which we consolidated for financial reporting purposes and was included in our Offshore Pipelines and Services segment; iv) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House Class A units, which we accounted for as an equity method investment and was included in our Offshore Pipelines and Services segment; v) in February 2016, we completed the sale of our crude oil supply and logistics operations which was included in our Liquid Pipelines and Services segment; vi) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which were reported in our Gas Gathering and Processing Services segment; vii) in December 2013, we acquired Blackwater, which was reported in our Terminalling Services segment; and viii) in April 2013, we acquired the High Point System, which was included in our Natural Gas Transportation Services segment.

(3) Includes unvested phantom units with distribution equivalent rights ("DERs"), which are considered participating securities, 200,000 units at December 31, 2017 and 2016.

(4) 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, see Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations. Adjusted EBITDA of the year ended December 31, 2016 has been revised to be consistent with all periods presented. See further information in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations, How We Evaluate Our Operations of this Annual Report.

(5) For a definition of Total segment 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 Total segment gross margin to evaluate our operating performance, see Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations.

(6) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, see Item 7. Management's Discussion and Analysis — Our Operations - Gas Gathering and Processing Services 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 five reportable segments, (i) gas gathering and processing services, (ii) liquid pipelines and services, (iii) natural gas transportation services, (iv) offshore pipelines and services and (v) terminalling services, 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 and refined products. As of September 1, 2017, as a result of the disposition of the Propane Business described in in Note 4 - Discontinued Operations, in Part II, Item 8 of this Annual Report, we have eliminated the Propane Marketing Services segment.

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 liquid pipelines, natural gas transportation and offshore pipelines and terminal assets are located in prolific producing regions and key demand markets in Alabama, Louisiana, Mississippi, North Dakota, Texas, Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia. Additionally, we operate a fleet of NGL gathering and transportation trucks in the Eagle Ford shale and the Permian Basin. See Recent Developments in Part I, Item 1 of this Annual Report for more information about our recent acquisitions and dispositions.

We own or have ownership interests in more than 5,100 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 17 gathering systems, seven interstate pipelines and nine intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 90 MBbl/d of crude oil and 220 MMcf/d of natural gas; six marine terminal sites with approximately 6.7 MMBbls of above-ground aggregate storage capacity for petroleum products, distillates, chemicals and agricultural products; and 90 transportation trucks and a total trailer fleet of 130, of which 35 are LPG trailers and 95 are crude oil trailers.

A portion of our cash flow is derived from our investments in unconsolidated affiliates, including a 66.67% operated interest in Destin, a natural gas pipeline; a 66.7% operated interest in Okeanos, a natural gas pipeline; a 35.7% non-operated interest in the Class A units and common units of Delta House, a floating production system platform and related pipeline infrastructure; a 25.3% non-operated interest in Wilprise, an NGL pipeline; a 16.7% non-operated interest in Tri-States, an NGL pipeline; and up to August 8, 2017, prior our acquisition of Panther, a 66.7% interest in MPOG, a crude oil gathering and processing system. Subsequent to the acquisition of Panther, we consolidated and wholly owned MPOG.

Financial Highlights

Financial highlights during the year ended December 31, 2017, include the following:

• Net loss attributable to the Partnership increased to $223.0 million, or an increase of 334.6%, as compared to net loss of $51.3 million in 2016, which was primarily due to a combination of an increase in operating loss of $233.9 million, including non cash impairment charges of $194.6 million, and increased interest expense of $45.0 million associated with higher average debt balances from our growth initiatives as well as higher average interest costs, offset by the net gain on disposition of the Propane Business of $47.4 million and the gain of $36.0 million related to the MPOG acquisition. The impairment charges of $194.6 million, of which $116.6 million was associated with our property, plant and equipment and intangible assets associated with certain non core assets in our Gas Gathering and Processing Services segment and our Liquid Pipelines and Services segment and approximately $78.0 million in goodwill, associated with certain assets in our Liquid Pipelines and Services segment. See Note 9 - Property, Plant and Equipment and Note 10 - Goodwill and Intangible Assets, Net in Part II, Item 8 of this Annual Report for more information.

• Earnings in unconsolidated affiliates were $63.1 million, an increase of $22.9 million as compared to $40.2 million for the same period in 2016, which was primarily due to an increase of $13.2 million due to the incremental ownership in Delta House in the fourth quarter of 2016 and our subsequent increases in ownership in November 2017, $5.4 million from Destin as a result of twelve months of ownership reflected in 2017 as compared to eight months of ownership in 2016, as well as higher volumes on our Okeanos system for $4.0 million. Additionally, there was a $3.0 million increase driven by increasing volumes on Tri-States and Wilprise due to new wells (production) from the

Thunderhorse platform.

• Segment gross margin amounted to $242.1 million, or an increase of $18.5 million as compared to $223.6 million of the same period in 2016. This increase of $18.5 million was primarily due to our Offshore Pipelines and Services segment earnings from unconsolidated affiliates of $19.8 million, $1.6 million from firm transportation contracts of 150 MMcf/d on MLGT, $1.0 million from new Midla Natchez contracts with higher rates, $1.0 million from the acquisition of Trans-Union in November 2017, partially offset by a decrease in our Terminalling Services segment of $4.9 million primarily attributable to a decrease in Cushing storage, higher operating costs at our Harvey terminal, and higher butane costs.

• Adjusted EBITDA decreased to $176.4 million, or an immaterial decrease of 0.7%, as compared to $177.6 million in 2016.

• We distributed $89.4 million to our common unitholders, or $1.65 per common unit, with respect to the year 2017. Our fourth quarter 2017 distribution was the 26th consecutive distribution since our initial public offering.

Operational highlights during the year ended December 31, 2017, include the following:

• Contracted capacity for our Terminalling Services segment averaged 4,957,328 Bbls, representing a 1.1% decrease compared to the same period in 2016;

• Average condensate production totaled 64 Mgal/d, representing a 18.9 Mgal/d or 22.8% decrease compared to the same period in 2016;

• Average gross NGL production totaled 326 Mgal/d, representing a 133 Mgal/d or 68.7 % increase compared to the same period in 2016;

• Throughput volumes attributable to the Natural Gas Transportation Services and Offshore Pipelines and Services segments totaled 730 MMcf/d, representing a 126 MMcf/d or 14.7% decrease compared to the same period in 2016;

• Throughput volumes attributable to the Liquid Pipelines and Services segment totaled 34,248 Bbls/d, representing a 1,991 Bbls/d or 6.2% increase compared to the same period in 2016; and

• The percentage of gross margin generated from fee based, fixed margin, firm and interruptible transportation contracts and firm storage contracts was 89.1%, representing a decrease of 2.5%, as compared to the same period in 2016.

Our Operations

We manage our business and analyze and report our results of operations through five reportable segments.

• Gas Gathering and Processing Services. Our Gas Gathering and Processing Services segment provides "wellhead-to-market" services to producers of natural gas and NGLs, which include transporting raw natural gas 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.

• Liquid Pipelines and Services. Our Liquid Pipelines and Services segment provides transportation, purchase and sales of crude oil from various receipt points including lease automatic customer transfer ("LACT") facilities and deliveries to various markets.

• Natural Gas Transportation Services. Our Natural Gas Transportation Services 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.

• Offshore Pipelines and Services. Our Offshore Pipelines and Services segment gathers and transports natural gas and crude oil from various receipt points to other pipeline interconnects, onshore facilities and other delivery points.

• Terminalling Services. Our Terminalling Services 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 and also includes crude oil storage in Cushing, Oklahoma and refined products terminals in Texas and Arkansas.

Gas Gathering and Processing Services Segment

Results of operations from the Gas Gathering and Processing Services segment are determined primarily by the volumes of natural gas 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 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.

• 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 offspec 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 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 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. See the information set forth in Part II, Item 7A of this Annual Report under the caption — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.

Liquid Pipelines and Services Segment

Results of operations from the Liquid Pipelines and Services segment are determined by the volumes of crude oil transported on the interstate and intrastate pipelines we own. Tariffs associated with our Bakken system are regulated by FERC for volumes gathered via pipeline and trucked to the AMID Truck facility in Watford City, North Dakota. Volumes transported on our Silver
Dollar system are underpinned by long-term, fee-based contracts. Our transportation arrangements are further described below:

• Firm Transportation Arrangements. Our obligation to provide firm transportation service means that, pursuant to the agreement with the shipper, we transport crude oil 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.

• Uncommitted Shipper Arrangements. Our obligation to provide interruptible transportation service means that, pursuant to the agreement with the shipper, we only transport crude oil 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.

• Fee-Based Arrangements. Under these arrangements our operations are underpinned by long-term, fee-based contracts with leading producers in the Midland Basin. Some of these contracts also have minimum volume commitments as well as some have acreage dedications.

• Buy-Sell Arrangements. We enter into outright purchase and sales contracts as well as buy/sell contracts with counterparties, under which contracts we gather and transport different types of crude oil and eventually sell the crude oil to either the same counterparty or different counterparties. We account for such revenue arrangements on a gross basis. Occasionally, we enter into crude oil inventory exchange arrangements with the same counterparty which the purchase and sale of inventory are considered in contemplation of each other. Revenues from such inventory exchange arrangements are recorded on a net basis.

Natural Gas Transportation Services Segment

Results of operations from the Natural Gas Transportation Services segment are determined by capacity reservation fees from firm and interruptible 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, pursuant to the agreement with the shipper, we 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 or commodity charge with respect to quantities actually transported by us.

• Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that, pursuant to the agreement with the shipper, we only 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 or commodity 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.

Offshore Pipelines and Services

Results of operations from the Offshore Pipelines and Services segment are determined by capacity reservation fees from firm and interruptible 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, pursuant to the agreement with the shipper, we 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 or commodity charge with respect to quantities actually transported by us.

• Interruptible Transportation Arrangements. Our obligation to provide interruptible transportation service means that, pursuant to the agreement with the shipper, we only transport natural gas nominated by the shipper to the extent that we have available capacity. For this service the shipper pays no reservation charge or commodity 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.

Terminalling Services Segment

Our Terminalling Services 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, truck weighing, etc. Our firm storage contracts are typically multi-year contracts with renewal options. Our refined products terminals have butane blending capabilities.

Our Terminalling Services 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 Terminalling Services 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.

Cash distributions received from our unconsolidated affiliates amounted to $90.8 million, $83.0 million, and $20.6 million for the years ended December 31, 2017, 2016, and 2015, respectively. Cash distributions derived from our unconsolidated affiliates 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, total segment gross margin, operating margin, direct operating expenses on a segment basis, and Adjusted EBITDA on a company-wide basis.

Throughput Volumes

In our Gas Gathering and Processing Services segment, we must continually obtain new supplies of natural gas, NGLs and condensate to maintain or increase throughput volumes on our systems. Our ability to maintain or increase existing volumes of natural gas, 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, NGLs and condensate that has been released from other commitments and iv) the volume of natural gas, 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 Liquid Pipelines and Services segment, the amount of revenue we generate from our crude oil pipelines business depends primarily on throughput volumes. We generate a portion of our crude oil pipeline revenues through long-term contracts containing acreage dedications or minimum volume commitments. Throughput volumes on our pipeline system are affected primarily by the supply of crude oil in the market served by our assets. The revenue generated from our crude oil supply and logistics business depends on the volume of crude oil we purchase from producers, aggregators and traders and then sell to producers, traders and refiners as well as the volumes of crude oil that we gather and transport. The volume of our crude oil supply and logistics activities and the volumes transported by our crude oil gathering and transportation trucks are affected by the supply of crude oil in the markets served directly or indirectly by our assets. Accordingly, we actively monitor producer activity in the areas served by our crude oil supply and logistics business and other producing areas in the United States to compete for volumes from crude oil producers. Revenues in this business are also impacted by changes in the market price of commodities that we pass through to our customers.

In our Natural Gas Transportation Services and Offshore Pipelines and Services segments, 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 the 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 Terminalling Services 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 at our marine terminals. The amount of revenue we generate from our refined products terminals depends primarily on the volume of refined products that we handle. These volumes are affected primarily by the supply of and demand for refined products in the markets served directly or indirectly by our refined products terminals. Our refined products have butane blending capabilities. The volume of crude oil stored at our crude oil storage facility in Cushing, Oklahoma has no impact on the revenue generated by our crude oil storage business because we receive a fixed monthly fee per barrel of shell capacity that is not contingent on the usage of our storage tanks.

Storage Utilization

Storage utilization is a metric that we use to evaluate the performance of our Terminalling Services 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 Total Segment Gross Margin

Segment gross margin and total segment gross margin are metrics that we use to evaluate our performance.

We define segment gross margin in our Gas Gathering and Processing Services segment as total revenue plus unconsolidated affiliate earnings less unrealized gains (losses) on commodity derivatives, construction and operating management agreement income and less the cost of sales.

We define segment gross margin in our Liquid Pipelines and Services segment as total revenue plus unconsolidated affiliate earnings less unrealized gains (losses) on commodity derivatives and less the cost of sales 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 Natural Gas Transportation Services segment as total revenue plus unconsolidated affiliate earnings less the cost of sales 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 Offshore Pipelines and Services segment as total revenue plus unconsolidated affiliate earnings less the cost of sales 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 Terminalling Services segment as total revenue less cost of sales and direct operating expense which includes direct labor, general materials and supplies and direct overhead.

Total segment gross margin is a supplemental non-GAAP financial measure that we use to evaluate our performance. We define total segment gross margin as the sum of the segment gross margins for our Gas Gathering and Processing Services, Liquid Pipelines and Services, Natural Gas Transportation Services, Offshore Pipelines and Services, and Terminalling Services segments. The GAAP measure most directly comparable to total segment gross margin is Net loss attributable to the Partnership. For a reconciliation of total segment gross margin to net loss, see Non-GAAP Financial Measures below.

Operating Margin

We define operating margin as total segment gross margin less other direct operating expenses. The GAAP measure most directly comparable to operating margin is net loss attributable to the Partnership. For a reconciliation of operating margin to net loss, see 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 loss attributable to the Partnership, plus depreciation, amortization and accretion expense, interest expense, debt issuance cost, unrealized losses on derivatives, non-cash charges such as non-cash equity compensation expense, and charges that are unusual such as transaction expenses primarily associated with our acquisitions (such as JPE, VKGS, Delta House, Panther and Trans-Union), income tax expense, distributions from unconsolidated affiliates and our General Partner's contribution, less earnings in unconsolidated affiliates, gains (losses) that are unusual such as gain on revaluation of equity interest, and the gain on sale of the Propane Business, other, net and gain on sale of assets, net.

The GAAP measure most directly comparable to our performance measure Adjusted EBITDA is net loss attributable to the Partnership. For a reconciliation of net loss to Adjusted EBITDA , see Non-GAAP Financial Measures below.

Note about Non-GAAP Financial Measures

Total segment gross margin, operating margin and Adjusted EBITDA are performance measures that are non-GAAP financial measures. Each has important limitations as an analytical tool because they exclude 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 total segment 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. Total segment 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 total segment gross margin, operating margin and Adjusted EBITDA used by management to Net loss attributable to the Partnership, their most directly comparable GAAP measure, for the years ended December 31, 2017, 2016, and 2015 (in thousands):

	Years Ended December 31,		
	2017 [1]	2016 [2] (In thousands)	2015 [2]
Reconciliation of Total Segment Gross Margin to Net loss attributable to the Partnership			
Gas Gathering and Processing Services	$49,010	$48,245	$65,692
Liquid Pipelines and Services	27,999	31,556	26,399
Natural Gas Transportation Services	23,424	18,616	18,073
Offshore Pipelines and Services	103,664	82,346	33,613
Terminalling Services	37,987	42,872	36,079
Total Segment Gross Margin	242,084	223,635	179,856
Less:			
Direct operating expenses [3]	67,617	60,762	61,315
Operating margin	174,467	162,873	118,541
Add:			
Gains (losses) on commodity derivatives, net	(119)	(1,617)	1,345
Deduct:			
Corporate expenses	112,058	89,438	65,327
Depreciation, amortization and accretion	103,448	90,882	81,335
(Gain) loss on sale of assets, net	(4,063)	688	2,860
Impairment of long-lived assets / intangible assets	116,609	697	—
Impairment of goodwill	77,961	2,654	148,488
Interest expense	66,465	21,433	20,077
Other income	(36,254)	(254)	(1,460)
Other, net [4]	(510)	(3,033)	792
Income tax expense	1,235	2,580	1,885
(Income) loss from discontinued operations, net of tax	(44,095)	4,715	423
Net income (loss) attributable to noncontrolling interest	4,473	2,766	(13)
Net loss attributable to the Partnership	$(222,979)	$(51,310)	$(199,828)

During these years, we had the following transactions that affect comparability:

(1) i) In June 2017, we acquired a 100% interest in VKGS which is accounted for as a business combination and is included in our Offshore Pipelines and Services segment; ii) in August 2017, we acquired a 100% interest in POGS, the outstanding interests in one of our equity investments MPOG, which is accounted for as a change in control and has been consolidated from the acquisition date; and the remaining equity interest in our consolidated subsidiary, AmPan, each of which are included in our Offshore Pipelines and Services segment; iii) in September 2017, we acquired an additional 15.5% equity interest in Delta House Class A units, which we account for as an equity method investment and is included in our Offshore Pipelines and Services segment; iv) in October 2017, we acquired an additional 17.0% membership interest in Destin which we account for as an equity method investment and is included in our Liquid Pipelines and Services segment and v) in November 2017, we acquired 100% of the equity interest in Trans-Union which represents an asset acquisition among entities under common control and is included in our Natural Gas Transportation Services segment.

(2) i) In October 2016 and April 2016, we acquired 6.2% and 1% non-operated interests in Delta House Class A units which we account for as equity method investments and are included in our Offshore Pipelines and Services segment; ii) in April 2016, we acquired membership interests in Destin (66.7%), Tri-States (16.7%), Okeanos (66.7%), and Wilprise (25.3%), which we account for as equity method investments and are included in our Liquid Pipelines and Services and Offshore Pipelines and Services segments; iii) in April 2016 we acquired a 60% interest in American Panther which we consolidate for financial reporting purposes and is included in our Offshore Pipelines and Services segment; 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 is included in our Offshore Pipelines and Services segment; and v) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which are included in our Gas Gathering and Processing Services segment.

(3) Direct operating expenses includes Gas Gathering and Processing Services segment direct operating expenses of $32.0 million, $33.8 million, and $35.3 million for the years ended December 31, 2017, 2016 and 2015, respectively, Liquid Pipelines and Services segment direct operating expenses of $12.3 million, $10.1 million, and $9.9 million for the years ended December 31, 2017, 2016 and 2015, respectively, Natural Gas Transportation Services segment direct operating expenses of $6.3 million, $5.9 million, and $6.7 million for the years ended December 31, 2017, 2016 and 2015, respectively, and Offshore Pipelines and Services segment direct operating expenses of $17.0 million, $10.9 million, and $9.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. Direct operating expenses exclude amounts related to the Terminalling Services segment as those costs are included in segment gross margin for the Terminalling Services segment.

(4) Other, net includes realized gain (loss) on commodity derivatives of $(0.1) million, $(1.6) million and $1.6 million and COMA income of $0.3 million, $1.5 million and $0.8 million, respectively, for each of the years ended December 31, 2017, 2016, and 2015, respectively.

	Years Ended December 31,		
	2017	2016[2]	2015
Reconciliation of Net loss attributable to the Partnership to Adjusted EBITDA:			
Net loss attributable to the Partnership	$(222,979)	$(51,310)	$(199,828)
Add:			
Depreciation, amortization and accretion	102,766	90,882	81,335
Interest expense [2]	60,587	28,572	17,686
Debt issuance costs paid	5,705	5,328	2,244
Unrealized (gain) loss on derivatives, net	(1,106)	(10,328)	495
Non-cash equity compensation expense	8,032	5,658	5,080
Corporate office relocation	—	9,096	—
Transaction expenses	42,860	14,084	3,303
Income tax expense	1,235	2,580	1,885
Impairment of long-lived assets / intangible assets	116,609	697	—
Impairment of goodwill	77,961	2,654	148,488
Distributions from unconsolidated affiliates	90,846	83,046	20,568
General Partner contribution for cost reimbursement	34,614	7,500	3,000
Deduct:			
Earnings in unconsolidated affiliates	63,050	40,158	8,201
Construction and operating management agreement income	392	1,465	841
Other post-employment benefits plan net periodic benefit	20	17	14
Gain (loss) on sale of assets, net	4,063	(688)	(2,860)
Gain on equity interest	35,999	—	—
Net impact of discontinued operations [1]	(37,212)	$30,058	$22,661
Adjusted EBITDA	$176,394	$177,565	$100,721

[1] Amounts primarily represent adjustments related to depreciation, amortization and accretion, unrealized (gain) loss on derivatives, (gain) loss on asset sales, goodwill impairment, our transaction expenses and gain on the sale of our Propane Business.
[2] Interest expenses and Adjusted EBITDA associated with the year ended December 31, 2016 have been revised from the recasted information filed by us on a Current Report on Form 8-K on December 7, 2017, as amended by a Current Report on Form 8-K/A filed on December 12, 2017. Interest expense, as presented above, includes interest expense as reported in our consolidated statement of operation minus amortization of deferred financing cost minus unrealized gain or loss in interest rate swaps.

General Trends and Outlook

During 2018, 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 expected gross margins.

We anticipate maintenance capital expenditures between $14.0 million and $19.0 million, and approved expenditures for expansion capital between $65.0 million and $85.0 million, for the year ending December 31, 2018. Forecast growth capital expenditures include East Texas Processing consolidation, expansion of the Harvey terminal, continued build-out of the Bakken system, continued development of the Silver Dollar 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 commodity prices in 2018 to increase compared to 2017 and as a result we expect producer and supplier activities to be impacted, which may increase the growth rate of our Gas Gathering and Processing Services and Natural

Gas Transportation Services segments. We also expect the SXE Transactions to be accretive to our Adjusted EBITDA upon consummation.

We expect our business to continue to be affected by the key trends and outlook 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.

In the fourth quarter of 2017, we were notified by the operator of FPS that certain third party-owned upstream infrastructure would require remedial work, resulting in a temporary curtailment of production flow at Delta House. This remediation is scheduled to be completed later in the second quarter of 2018, at which time full production is anticipated to resume flowing into Delta House.

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

Liquid Pipelines and Services Segment. The profitability of our Liquid Pipelines and Services segment is dependent upon the price of crude oil. Throughput volumes could decline should crude oil prices remain low resulting in decreased production in our areas of operation.

Natural Gas Transportation Services and Offshore Pipelines and Services Segments. Profitability of our Natural Gas Transportation Services and Offshore Pipelines and Services segments are 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.

Terminalling Services Segment. The profitability of our Terminalling Services 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 $66.27 per barrel to a low of $42.48 per barrel from January 1, 2017 through March 26, 2018. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.24 per MMBtu to a low of $2.44 per MMBtu from January 1, 2017 through March 26, 2018. 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 revolving credit facility, and our ability to maintain our current distribution levels. Our long-term view is that as economic conditions improve and regulation burden is reduced, as it has been the case under the current administration, commodity prices should reach levels that will support continued natural gas and crude oil production in the United States. Reduced profitability, if any, may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

On January 26, 2018 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 14, 2018, to unitholders of record as of the close of business on February 7, 2018. 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.

Results of Operations

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Net loss attributable to the Partnership increased to $223.0 million, or 334.6%, as compared to a net loss of $51.3 million in 2016, which was primarily due to a combination of an increase in the operating loss of $233.9 million, including non-cash impairment charges totaling $194.6 million related to non-core assets and goodwill, and increased interest expense of $45.0 million associated with higher average debt balances from our growth initiatives as well as higher average interest costs, offset primarily by the net gain on disposition of the Propane Business of $47.4 million and the gain of $36.0 million recognized in our consolidated statement of operations for the year ended December 31, 2017 related to the MPOG acquisition. This acquisition of the 33.3% remaining ownership of MPOG resulted in a change of control from investment in unconsolidated affiliates to a wholly-owned consolidated subsidiary, resulting in the recognized gain.

Total segment gross margin increased by $18.5 million, or 8.2%, for the year ended to December 31, 2017 to $242.1 million as compared to 2016. This increase of $18.5 million was primarily due to our Offshore Pipelines and Services segment earnings from unconsolidated affiliates of $19.8 million, $1.6 million from new firm transportation contracts of 150 MMcf/d on MLGT, $1.0 million from new Midla Natchez contracts with higher rates, and $1.0 million from the acquisition of Trans-Union in November 2017, partially offset by a decrease in our Terminalling Services segment of $4.9 million primarily attributable to a decrease in Cushing storage, higher operating costs at our Harvey terminal, and higher butane costs.

Adjusted EBITDA decreased to $176.4 million, or an immaterial decrease of 0.7%, as compared to $177.6 million in 2016.

We distributed $89.4 million and $112.1 million to holders of our common units during the years ended December 31, 2017 and 2016, 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,		
	2017	2016	2015
Statements of Operations Data:			
Revenues:			
Commodity sales	$496,902	$439,412	$613,241
Services	154,652	151,231	135,718
Gains (losses) on commodity derivatives, net	(119)	(1,617)	1,345
Total revenue	651,435	589,026	750,304
Operating expenses:			
Cost of sales	457,371	393,351	567,682
Direct operating expenses	82,256	71,544	71,729
Corporate expenses	112,058	89,438	65,327
Depreciation, amortization and accretion	103,448	90,882	81,335
(Gain) Loss on sale of assets, net	(4,063)	688	2,860
Impairment of long-lived assets / intangible assets	116,609	697	—
Impairment of goodwill	77,961	2,654	148,488
Total operating expenses	945,640	649,254	937,421
Operating loss	(294,205)	(60,228)	(187,117)
Other income (expenses):			
Interest expense	(66,465)	(21,433)	(20,077)
Other income	36,254	254	1,460
Earnings in unconsolidated affiliates	63,050	40,158	8,201
Loss from continuing operations before income taxes	(261,366)	(41,249)	(197,533)
Income tax expense	(1,235)	(2,580)	(1,885)
Loss from continuing operations	(262,601)	(43,829)	(199,418)
Income (loss) from discontinued operations, net of tax	44,095	(4,715)	(423)
Net loss	(218,506)	(48,544)	(199,841)
Net income (loss) attributable to noncontrolling interests	4,473	2,766	(13)
Net loss attributable to the Partnership	$(222,979)	$(51,310)	$(199,828)
Other Financial Data [(1)]:			
Total segment gross margin	$242,084	$223,635	$179,856
Adjusted EBITDA	$176,394	$177,565	$100,721

[(1)] For definitions of Total segment 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 Total segment gross margin and Adjusted EBITDA to evaluate our operating performance, see the information in this Item under the caption How
We Evaluate Our Operations.

Year ended December 31, 2017, compared to year ended December 31, 2016

Commodity Sales. Commodity sales revenue for the year ended December 31, 2017 was $496.9 million compared to $439.4 million for the year ended December 31, 2016. This increase of $57.5 million was primarily due to the following:

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- an increase in our Gas Gathering and Processing Services segment from sales of NGLs and condensate at the Longview plant of $44.4 million due to new contracts;
- an increase in our Liquid Pipelines and Services segment due to a net increase in marketing contracts totaling $15.4 million;
- an increase in our Natural Gas Transportation Services segment of $3.3 million due to higher average index prices on our Magnolia system;
- an increase in our Offshore Pipelines and Services segment of $4.7 million due to higher volumes as a result of a new well drilled in December 2016 at Mud Lake, Louisiana on our Gloria system;
- an increase in our Terminalling Services segment of $1.2 million driven by an increase in butane blending sales pricing at our Caddo Mills facility; which were
- partially offset by the reduced NGL and condensate volumes in our Gas Gathering and Processing Services segment at our Chatom/Bazor Ridge plants for $11.5 million due to lower system volumes from production declines, the loss of Y-grade product and plant downtime in the fourth quarter of 2017.

Services Revenue. Our service revenue for the year ended December 31, 2017 was $154.7 million compared to $151.2 million for the year ended December 31, 2016. This increase of $3.5 million was primarily due to the following:

- an increase of $7.0 million from higher management fees on AmPan;
- an increase of $5.3 million due to the VKGS acquisition in June 2017;
- an increase of $1.6 million due to Firm Transportation agreements (150 MMcf/d) on MLGT;
- an increase of $1.0 million due to higher rates on our new Midla Natchez line;
- an increase of $1.0 million due to the Trans-Union acquisition in November 2017; which were
- partially offset by various items on our High Point Gathering Transmission ("HPGT") line for $10.0 million from the shut-in of our dry line, firm transportation contract expirations, Hurricane Nate impacts and compressor maintenance; and
- increased trucking activities on AMID Liquid Trucking with our own affiliates resulting in reduced third-party trucking revenues of $3.4 million.

Cost of sales. Cost of sales for the year ended December 31, 2017, was $457.4 million compared to $393.4 million in the year ended December 31, 2016. This increase of $64.0 million was primarily due to net new marketing transactions in 2017 compared to 2016 of $16.7 million in our Liquid Pipelines and Services segment, $34.4 million mostly due to increase of NGL, natural gas and condensate transactions at the Longview plant, $3.6 million due to the addition of a new well at Mud Lake, Louisiana on our Gloria system, and $2.7 million due to higher average index prices on our Magnolia system.

Total Segment Gross Margin. Total segment gross margin for the year ended December 31, 2017, was $242.1 million compared to $223.6 million for the year ended December 31, 2016. This increase of $18.6 million was primarily due to our Offshore Pipelines and Services segment earnings from unconsolidated affiliates of $19.8 million, $1.6 million from new firm transportation contracts of 150 MMcf/d on MLGT, $1.0 million from new Midla Natchez contracts with higher rates, $1.0 million from the acquisition of Trans-Union in November 2017, partially offset by our Terminalling Services segment of $5.1 million primarily attributable to a decrease in Cushing storage, higher operating costs at our Harvey terminal, and higher butane costs.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2017 were $82.3 million compared to $71.5 million for the year ended December 31, 2016. This increase of $10.8 million was primarily due to a $2.3 million increase associated with the acquisition of VKGS, $1.7 million due to the Panther acquisition, and $1.8 million incremental operating expenses pertaining to our Harvey facility expansion as a result of higher repairs and maintenance, contractor services and security costs, $1.7 million due to employee headcount increases, $1.3 million in environmental regulatory compliance costs, and $0.9 million in additional repairs and maintenance.

Corporate Expenses. Corporate expenses for the year ended December 31, 2017, were $112.1 million compared to $89.4 million for the year ended December 31, 2016. This increase of $22.6 million was primarily due to transaction related costs associated with the JPE merger and the SXE Transactions of $14.8 million, $4.0 million in audit and tax fees, $2.7 million in legal and regulatory compliance fees in support of corporate activities, and $1.1 million due to information and technology costs related to systems and licenses that were either implemented or initiated during 2017.

Depreciation, Amortization and Accretion. Depreciation, amortization and accretion for the year ended December 31, 2017, was $103.4 million compared to $90.9 million for the year ended December 31, 2016. This increase of $12.6 million was primarily due to the acceleration of the accumulated amortization of a JPE customer relationship carried out in the beginning of the first quarter of 2017 through August 2017 for $10.0 million. The remaining difference is primarily due to increases in depreciation, amortization and accretion related to our Panther acquisition in the third quarter of 2017 and the Trans-Union acquisition in the fourth quarter of 2017.

Impairment of Long-lived assets / intangible assets. During the fourth quarter of 2017, we identified certain assets where events or circumstances indicated we may not recover their carrying value. Due to plant shut downs in the quarter and changes in our forecast volumes on certain assets, as part of our annual budget process we have made operational decisions that impact our ability to recover the carrying value of assets. As a result, asset impairment charges of $116.6 million were recorded in the fourth quarter of 2017, of which $103.9 million was related to our property, plant and equipment and $12.7 million was related to intangible assets. Of the $103.9 million impairment charge to our property, plant and equipment, $97.8 million related to our Gas Gathering and Processing Services segment, $3.9 million related to our Natural Gas Transportation Services segment and $2.2 million related to our Liquid Pipelines and Services segment. Additionally, of the $12.7 million impairment charge to our intangible assets, $10.8 million related to our Gas Gathering and Services segment and $1.9 million related to our Liquid Pipelines and Services segment.

Impairment of Goodwill. Goodwill impairment expense for the year ended December 31, 2017 was $78.0 million compared to $2.7 million for the year ended December 31, 2016. In 2017, we recognized goodwill impairment charges totaling $78.0 million to our Liquid Pipelines and Services segment. In 2016, we recognized goodwill impairment charges totaling $2.7 million related to our JP Liquids business.

Interest Expense. Interest expense for the year ended December 31, 2017, was $66.5 million compared to $21.4 million for the year ended December 31, 2016. This increase of $45.1 million was primarily due to higher outstanding borrowings under our revolving credit facilities, and an increase in our weighted-average interest rate.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2017 were $63.1 million compared to $40.2 million for the year ended December 31, 2016. This increase of $22.9 million was primarily due to the incremental ownership in Delta House in the fourth quarter of 2016 and our subsequent increases in ownership in November 2017 for $11.2 million, $5.4 million on Destin as a result of twelve months of ownership reflected in 2017 compared to eight months of ownership in 2016, as well as higher volumes on our Okeanos system for $4.0 million. Additionally, there was a $3.0 million increase driven by increasing volumes on Tri-States and Wilprise due to new wells (production) from the Thunderhorse platform.

Income (Loss) from Discontinued Operations. Income (loss) from discontinued operations represents the Partnership's income (loss) from the discontinued operations, including gain or loss on sales. Income from discontinued operations, net of tax for the year ended December 31, 2017 of $44.1 million was associated with the sale of the Propane Business on September 1, 2017, whereas loss from discontinued operations, net of tax for the year ended December 31, 2016, of $4.7 million was associated primarily with the sale of the Mid-Continent Business on February 1, 2016. See Note 4 - Discontinued Operations.

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

Commodity Sales. Commodity sales for the year ended December 31, 2016 was $439.4 million compared to $613.2 million for the year ended December 31, 2015. This decrease of $173.8 million was primarily due to the following:

- a decrease in crude oil sales revenue of $152.9 million due to a decrease in sales volumes of 15,830 (bbls/day) from an overall reduction in our customer crude oil production volumes in our areas of operation;
- 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;
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- 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;
- a decrease in NGL revenues of $6.3 million due to lower gross NGL production volumes of 38.2 Mgal/d from our Gas Gathering and Processing Services segment and lower realized NGL prices of $0.57/gal, which is a decrease of $0.01/gal period over period; and
- these decreases were partially offset by an increase in crude oil gathering fee-based revenues of $4.7 million.

Services Revenue. Our service revenue for the year ended December 31, 2016 was $151.2 million compared to $135.7 million for the year ended December 31, 2015. This increase of $15.5 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 (the "Gulf of Mexico Pipeline") which we acquired from Chevron Pipeline Company and Chevron Midstream Pipeline, LLC 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; and

- an increase in Terminalling Services segment revenue of $9.8 million as a result of incremental storage utilization and ancillary increases.

Cost of Sales. Cost of sales for the year ended December 31, 2016 was $393.4 million compared to $567.7 million in the year ended December 31, 2015. This decrease of $174.3 million was due to lower natural gas purchases of $10.4 million. There was also a decrease in crude oil purchases of $162.8 million which was driven by the 2016 reduction in crude sales volumes and overall reduction in crude prices. The NGL purchases decrease was primarily due to the reduction in NGL sales volumes. NGL sales volumes decreased 30,000/gallons per day in 2016 compared to 2015 due to a decline in volumes associated with oilfield services as a result of lower exploration and production activity and overall warmer than normal temperatures.

Total Segment Gross Margin. Total segment gross margin for the year ended December 31, 2016 was $223.6 million compared to $179.9 million for the year ended December 31, 2015. This increase of $43.7 million was primarily due to our increased Offshore Pipelines and Services segment gross margin of $8.5 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. Additionally, the incremental earnings from our equity method investees increased by $32.0 million, of which $29.9 million was attributable to our Offshore Pipelines and Services segment.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $71.5 million compared to $71.7 million in the year ended December 31, 2015. This decrease of $0.2 million was primarily due to a decrease of contract services and labor costs.

Corporate Expenses. Corporate expenses for the year ended December 31, 2016 were $89.4 million compared to $65.3 million for the year ended December 31, 2015. This increase of $24.1 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. Depreciation, amortization and accretion for the year ended December 31, 2016 was $90.9 million compared to $81.3 million for the year ended December 31, 2015. This increase of $9.6 million was primarily due to incremental depreciation of fixed assets related to our Gulf of Mexico Pipeline acquisition in April 2016, our Mesquite joint venture which began operations in April 2016, and our Bakken system which began operations in October 2015.

Impairment of Goodwill. Goodwill impairment expense for the year ended December 31, 2015 was $148.5 million compared to $2.7 million for the year ended December 31, 2016. The 2015 impairment charges were comprised of $95.0 million and $23.6 million related to the Costar and Lavaca assets, respectively, which were acquired in prior years, and $29.9 million in our Liquid Pipelines and Services reportable segment relating to the Crude Oil Supply and Logistics business. The 2016 impairment charges of $2.7 million were related to our JP Liquids business.

Interest Expense. Interest expense for the year ended December 31, 2016, was $21.4 million compared to $20.1 million for the year ended December 31, 2015. This increase of $1.3 million was primarily due to higher outstanding borrowings under our revolving credit facilities, and an increase in our weighted average interest rate, offset by $10.4 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.

Discontinued Operations. Loss from discontinued operations for the year ended December 31, 2016 was $4.7 million compared to $0.4 million for the year ended December 31, 2015. The increase in loss from discontinued operations of $4.3 million was primarily due to a decrease in gross margin of $1.9 million and $3.1 million associated with our Propane Business and Mid-Continent Business, respectively. The decrease in our Propane Business was primarily attributable to a reduction in NGL and refined product sales driven by a decline in volumes associated with oilfield services and overall warmer than normal temperatures sustained in the year ended December 31, 2016. The decrease in our Mid-Continent Business was primarily due to a decrease in crude oil sales volumes which was driven by a decline in oilfield services. Additionally, unrealized gains associated with the Propane commodity swaps decreased $10.7 million to $1.1 million as of December 31, 2016 from $11.8 million as of December 31, 2015, and loss on sale of assets related to the Propane Business increased $1.1 million for the year ended December 31, 2016.

These increases in loss from discontinued operations are partially offset by a decrease of $12 million related to direct operating expenses, corporate expenses, and depreciation and amortization.

Results of Operations — Segment Results

Gas Gathering and Processing Services Segment

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

	For the Years Ended December 31,		
	2017	2016	2015
Segment Financial and Operating Data:			
Gas Gathering and Processing Services Segment			
Financial data:			
Commodity Sales	$124,853	$91,444	$107,680
Services	21,900	22,558	30,196
Revenue from operations	146,753	114,002	137,876
Gain (loss) on commodity derivatives, net	310	(833)	1,240
Segment revenue	$147,063	$113,169	$139,116
Cost of sales	98,177	63,832	72,960
Direct operating expenses	32,003	33,802	35,250
Other financial data:			
Segment gross margin	$49,010	$48,245	$65,692
Operating data:			
Average throughput (MMcf/d)	202.0	220.6	240.0
Average plant inlet volume (MMcf/d) (1)	95.7	102.1	120.9
Average gross NGL production (Mgal/d) (1)	325.5	192.9	231.1
Average gross condensate production (Mgal/d) (1)	64.0	82.9	97.1

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

Year Ended December 31, 2017, Compared to Year Ended December 31, 2016

Commodity Sales. Commodity sales for the year ended December 31, 2017 were $124.9 million compared to $91.4 million for the year ended December 31, 2016. This increase of $33.5 million was primarily due to the following:

- increased revenue from sales of NGLs and condensate at the Longview plant of $44.4 million due to three new contracts, two of which started in the first quarter of 2017 and one ongoing contract; and
- offsetting this was reduced NGL and condensate volumes at our Chatom/Bazor Ridge plants of $11.5 million due to lower system volumes from production declines and the loss of Y-grade product and plant downtime in the fourth quarter of 2017.

Services Revenue. Services revenue for the year ended December 31, 2017 was $21.9 million compared to $22.6 million for the year ended December 31, 2016. This decrease of $0.7 million was primarily driven by lower drilling activity resulting in a decline in compression and gathering charges of $1.7 million on Lavaca, offset by an increase from a pipeline recovery fee of $1.3 million at Chatom/Bazor Ridge.

Cost of Sales. Cost of sales for the year ended December 31, 2017 was $98.2 million compared to $63.8 million for the year ended December 31, 2016. This increase of $34.4 million was primarily due to increase of NGL, natural gas and condensate sales at the Longview plant, as mentioned above, offset by reduced NGL and condensate volumes at Chatom/Bazor Ridge.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2017 was $49.0 million compared to $48.2 million for the year ended December 31, 2016. This increase of $0.8 million was mainly due to reasons discussed above under Commodity Sales.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2017 were $32.0 million compared to $33.8 million for the year ended December 31, 2016. This decrease of $1.8 million was primarily the result of lower compressor rentals for $0.8 million due to the ongoing cost cutting efforts and $0.7 million decrease in outside services at our Longview facility.

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

Commodity Sales. Commodity sales for the year ended December 31, 2016 was $91.4 million compared to $107.7 million for the year ended December 31, 2015. This decrease of $16.3 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 23.2%, 1.9%, and 10.9%, respectively; and
- lower average NGL and condensate production of 38.2 Mgal/d and 14.1 Mgal/d, respectively, primarily due to a decrease in volumes at our Longview system.

Services Revenue. Services revenue for the year ended December 31, 2016 was $22.6 million compared to $30.2 million for the year ended December 31, 2015. This decrease of $7.6 million was primarily due to lower average throughput and plant inlet volumes of 19.4 MMcf/d and 18.8 MMcf/d, respectively.

Cost of Sales. Cost of sales for the year ended December 31, 2016 was $63.8 million compared to $73.0 million for the year ended December 31, 2015. This decrease of $9.2 million was primarily due to lower realized commodity prices as well as lower NGL and condensate purchased volumes at our Longview system.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016 was $48.2 million compared to $65.7 million for the year ended December 31, 2015. This decrease of $17.5 million was primarily due to lower production on our Longview and Lavaca systems.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $33.8 million compared to $35.3 million for the year ended December 31, 2015. This decrease of $1.5 million was primarily due to lower compressor rentals due to ongoing cost cutting efforts.

Liquid Pipelines and Services Segment

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

	For the Years Ended December 31,		
	2017	2016	2015
Segment Financial and Operating Data:			
Liquid Pipelines and Services Segment			
Financial data:			
Commodity sales	$319,870	$304,502	$457,448
Services	16,411	19,063	23,008
Revenue from operations	336,281	323,565	480,456
Losses on commodity derivatives (net)	(429)	(341)	—
Earnings in unconsolidated affiliates	5,113	2,070	—
Segment revenue	$340,965	$325,294	$480,456
Cost of sales	312,830	293,618	454,057
Direct operating expense	12,330	10,091	9,912
Other financial data:			
Segment gross margin	$27,999	$31,556	$26,399
Operating data:			
Average throughput Pipeline (Bbls/d)	34,248	32,257	34,946
Average throughput Trucking (Bbls/d)	2,910	1,628	—

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Commodity Sales. Commodity sales for the year ended December 31, 2017 were $319.9 million compared to $304.5 million for the year ended December 31, 2016. This increase of $15.4 million was primarily due to a net increase in marketing contracts.

Services Revenue. Services revenue for the year ended December 31, 2017 was $16.4 million compared to $19.0 million for the year ended December 31, 2016. This decrease of $2.6 million was primarily due to increased activities in our Liquid Pipelines and Services segment with our affiliates resulting in a reduction in third party trucking revenue of $3.4 million, offset by a $0.7 million increase due to new exploration and production wells coming on-line in 2017 and associated capital recovery fees, and $0.5 million from increased trucking barrels.

Cost of Sales. Cost of sales for the year ended December 31, 2017 was $312.8 million compared to $293.6 million for the year ended December 31, 2016. This increase of $19.2 million was primarily due to the net increase in marketing contracts of $16.7 million.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2017 were $5.1 million compared to $2.1 million for the year ended December 31, 2016. This $3.0 million increase is driven by increasing volumes on Tri-States and Wilprise due to new wells (production) from the Thunderhorse platform.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2017 was $28.0 million compared to $31.6 million for the year ended December 31, 2016. This decrease of $3.6 million was due to the reasons discussed above.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2017 were $12.3 million compared to $10.1 million for the year ended December 31, 2016. This increase of $2.2 million was primarily due to the $1.5 million incremental expenses associated with our Crude Trucking bulk purchases of vehicle diesel and lubricants and $0.7 million due to Silver Dollar Pipeline employee headcount and contract services increase.

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

Commodity Sales. Commodity sales for the year ended December 31, 2016 were $304.5 million compared to $457.4 million for the year ended December 31, 2015. This decrease of $152.9 million was primarily due to a decrease in crude oil sales volumes to 24,425 barrels per day for the year ended December 31, 2016 from 40,255 barrels per day for the year ended December 31, 2015. These decreases are primarily due to an overall reduction in our customer crude oil production volumes in our areas of operation.

Services Revenue. Services revenue for the year ended December 31, 2016 was $19.1 million compared to $23.0 million for the year ended December 31, 2015. This decrease of $3.9 million was primarily due to reduction in NGL revenue from lower NGL trucking volumes driven by a decline in volumes associated with oilfield services and overall warmer than normal temperatures sustained in the year ended December 31, 2016. There was also a decrease in crude oil throughput volumes to 32,257 barrels per day for the year ended December 31, 2016 from 34,946 barrels per day for the year ended December 31, 2015. These decreases are due to an overall reduction in our customer crude oil production volumes in our areas of operation. However, producer activity around our Silver Dollar Pipeline increased, in late 2016, resulting in average pipeline throughput volumes of approximately 31,000 barrels per day in the quarter ended December 31, 2016.

Cost of Sales. Cost of sales for the year ended December 31, 2016 was $293.6 million compared to $454.1 million for the year ended December 31, 2015. This decrease of $160.5 million was primarily due to a decrease in crude oil sales volumes resulting from an overall reduction in our customer crude oil production volumes, as described above under Services Revenue.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2016 increased $2.1 million. This change was driven by the Emerald transaction that occurred in April 2016 adding interests in the Wilprise and Tri-States entities that own and operate pipeline systems.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016 was $31.6 million compared to $26.4 million for the year ended December 31, 2015. This increase of $5.2 million was primarily due to an increase in crude oil sales margin of $10.0 million due to the capturing of more favorable margins associated with previously stored inventory during contango market conditions as well as more favorable regional pricing spreads on bulk purchased crude oil. This increase was partially offset by a decrease in crude oil sales and throughput volumes of $6.9 million and $0.7 million, respectively.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $10.1 million compared to $9.9 million for the year ended December 31, 2015. This increase of $0.2 million was primarily due to the incremental expenses associated with our Bakken system, partially offset by reductions in personnel costs from lower headcount.

Natural Gas Transportation Services Segment

The table below contains key segment performance indicators related to our Natural Gas Transportation Services segment (in thousands except operating data).

	For the Years Ended December 31,		
	2017	2016	2015
Segment Financial and Operating Data:			
Natural Gas Transportation Services Segment			
Financial data:			
Commodity Sales	$25,376	$21,999	$23,972
Services	22,637	18,109	16,035
Segment revenue	$48,013	$40,108	$40,007
Cost of sales	24,211	21,288	21,858
Direct operating expenses	6,311	5,923	6,728
Other financial data:			
Segment gross margin	$23,424	$18,616	$18,073
Operating data:			

Average throughput (MMcf/d)	420.4	389.9	364.1

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Commodity Sales. Commodity sales for the year ended December 31, 2017 were $25.4 million compared to $22.0 million for the year ended December 31, 2016. This increase of $3.4 million was primarily due to higher average index prices on Magnolia.

Services Revenue. Services revenue for the year ended December 31, 2017 was $22.6 million compared to $18.1 million for the year ended December 31, 2016. This increase of $4.5 million was primarily due to new firm transportation contracts of 150 MMcfd on our MLGT pipeline for $1.6 million, $1.0 million on our new Midla Natchez line from contracts with higher rates, $1.0 million as a result of the Trans-Union acquisition in November 2017, and $0.7 million from additional contracts on AlaTenn.

Cost of Sales. Cost of sales for the year ended December 31, 2017 was $24.2 million compared to $21.3 million for the year ended December 31, 2016. This increase of $2.9 million was primarily due to higher average index prices on Magnolia.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2017 was $23.4 million compared to $18.6 million for the year ended December 31, 2016. This increase of $4.8 million was primarily due to reasons discussed above.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2017 were $6.3 million compared to $5.9 million for the year ended December 31, 2016. This increase of $0.4 million was primarily due to employee and contractor costs.

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

Commodity Sales. Commodity sales for the year ended December 31, 2016 were $22.0 million compared to $24.0 million for the year ended December 31, 2015. This decrease of $2.0 million was primarily due to lower realized natural gas prices of 10.1%.

Services Revenue. Services revenue for the year ended December 31, 2016 was $18.1 million compared to $16.0 million for the year ended December 31, 2015. This increase of $2.1 million was primarily due to higher average throughput volumes of 26 MMcf/d from firm transportation contracts associated with our MLGT pipeline.

Cost of Sales. Cost of sales for the year ended December 31, 2016 was $21.3 million compared to $21.9 million for the year ended December 31, 2015. This decrease of $0.6 million was primarily due to a decline in realized natural gas prices, as described above under Commodity Sales.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016 was $18.6 million compared to $18.1 million for the year ended December 31, 2015. This increase of $0.5 million was primarily due to higher average throughput volumes offset by lower realized natural gas prices.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $5.9 million compared to $6.7 million for the year ended December 31, 2015. This decrease of $0.8 million was primarily due to lower employee costs.

Offshore Pipelines and Services Segment

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

	For the Years Ended December 31,		
	2017	2016	2015
Segment Financial and Operating Data:			
Offshore Pipelines and Services Segment			
Financial data:			
Commodity sales	$11,508	$6,812	$13,798

Services	43,517	40,502	21,457
Revenue from operations	55,025	47,314	35,255
Gains (losses) on commodity derivatives, net	—	(7)	84
Earnings in unconsolidated affiliates	57,937	38,088	8,201
Segment revenue	$112,962	$85,395	$43,540
Cost of sales	9,298	3,049	9,914
Direct operating expense	16,973	10,945	9,425
Other financial data:			
Segment gross margin	$103,664	$82,346	$33,613
Operating data:			
Average throughput (MMcf/d)	309.6	466.4	442.8

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Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Commodity Sales. Commodity sales for the year ended December 31, 2017 were $11.5 million compared to $6.8 million for the year ended December 31, 2016. This increase of $4.7 million was primarily due to a new well in December 2016 at Mud Lake, Louisiana on our Gloria system.

Services Revenue. Services revenue for the year ended December 31, 2017 was $43.5 million compared to $40.5 million for the year ended December 31, 2016. This increase of $3.0 million was primarily due to $7.0 million of higher management fees on AmPan, and $5.3 million due to the acquisition of VKGS in June 2017, offset by a $10.0 million reduction on HPGT resulting from the shut-in of the dry line, firm transportation contract expiration, Hurricane Nate impacts, and compressor maintenance.

Cost of Sales. Cost of sales for the year ended December 31, 2017 was $9.3 million compared to $3.0 million for the year ended December 31, 2016. This increase of $6.3 million was primarily due to the addition of a new well in December 2016 at Mud Lake, Louisiana on our Gloria system for $3.6 million, $1.2 million due to imbalances on HPGT, $0.6 million of additional cost on Quivira as a result of a new condensate contract in November 2017, and $0.5 million due to the acquisition of VKGS in June 2017.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2017 were $57.9 million compared to $38.1 million for the year ended December 31, 2016. This increase of $19.8 million was primarily due to the incremental ownership in Delta House in the fourth quarter of 2016 and our subsequent increases in ownership in November 2017 for $11.2 million, $5.4 million on Destin as a result of twelve months of ownership reflected in 2017 versus eight months in 2016, as well as higher volumes on our Okeanos system for $4.0 million.

In the fourth quarter of 2017, a temporary delay of production volumes flowing into Delta House occurred, requiring remedial work which is scheduled to be completed later in the second quarter of 2018. This has resulted in a reduction in cash distributions from Delta House. On March 11, 2018, the Partnership and Magnolia, an affiliate of ArcLight, entered into a Capital Contribution Agreement by which Magnolia will provide additional capital and corporate overhead support to the Partnership for the first three quarters of 2018 in an amount up to the difference between the actual cash distribution received by the Partnership on account of its interest in Delta House and the quarterly cash distribution expected to be received if production flows to Delta House had not been not curtailed.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2017 was $103.7 million compared to $82.3 million for the year ended December 31, 2016. This increase of $21.4 million was primarily due to earnings in unconsolidated affiliates as noted above under Earnings in Unconsolidated Affiliates.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2017 were $17.0 million compared to $10.9 million for the year ended December 31, 2016. This increase of $6.1 million was primarily due to $3.9 million incremental expenses associated with our recent acquisitions (VKGS, $2.3 million, and Panther, $1.6 million), $1.5 million in environmental regulatory and compliance costs, and $0.7 million due to rental equipment costs.

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

Commodity Sales. Commodity sales for the year ended December 31, 2016 were $6.8 million compared to $13.8 million for the year ended December 31, 2015. This decrease of $7.0 million was primarily due to a reduction in the average realized prices for natural gas and condensate of 11.4% and 22.1%, respectively.

Services Revenue. Services revenue for the year ended December 31, 2016 was $40.5 million compared to $21.5 million for the year ended December 31, 2015. This increase of $19.0 million was primarily due to the Pascagoula plant shutdown which required volumes to be redirected to our High Point system, and increased fees associated with our acquisition of the Gulf of Mexico Pipeline. The Pascagoula plant is not controlled or owned by the Partnership.

Cost of Sales. Cost of sales for the year ended December 31, 2016 was $3.0 million compared to $9.9 million for the year ended December 31, 2015. This decrease of $6.9 million was primarily due to lower realized commodity prices, as described above under Commodity Sales.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2016 were $38.1 million compared to $8.2 million for the year ended December 31, 2015. This increase of $29.9 million was primarily due to the incremental investments in the Delta House entities in 2016, as well as the Emerald transaction that occurred in April 2016.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016 was $82.3 million compared to $33.6 million for the year ended December 31, 2015. This increase of $48.7 million was primarily due to increased revenues for our Highpoint system of $7.1 million as a result of the shutdown of the Pascagoula plant, increased fees associated with our acquisition of the Gulf of Mexico Pipeline of $12.5 million, incremental earnings of $22.8 million related to our investment in Delta House and $8.4 million associated with the offshore interests acquired in the Emerald transaction, partially offset by a decrease in commodity realized prices.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $10.9 million compared to $9.4 million for the year ended December 31, 2015. This increase of $1.5 million was primarily due to the incremental expenses associated with our acquisition of the Gulf of Mexico Pipeline, partially offset by lower employee costs.

Terminalling Services Segment

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

	For the Years Ended December 31,		
	2017	2016	2015
Segment Financial and Operating Data:			
Terminalling Services Segment			
Financial data:			
Commodity sales	$15,295	$14,655	$10,343
Services	50,186	50,999	45,022
Revenue from operations	65,481	65,654	55,365
Gains (losses) on commodity derivatives, net	—	(436)	21
Segment revenue	$65,481	$65,218	$55,386
Cost of sales	12,855	11,564	8,893
Direct operating expense	14,639	10,783	10,414
Other financial data:			
Segment gross margin	$37,987	$42,872	$36,079
Operating data:			
Contracted Capacity (Bbls)	4,957,328	5,011,133	4,487,542
Design Capacity (Bbls) (2)	5,400,800	5,173,717	4,688,950
Storage Utilization (1)	91.8 %	96.9 %	95.7 %
Terminalling and storage throughput (Bbls/d)	58,670	56,741	62,075

(1) Excludes storage utilization associated with our discontinued operations.
(2) Excludes 1.3 MBbls at our North Little Rock and Caddo Mills locations.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Commodity Sales. Commodity sales for the year ended December 31, 2017 were $15.3 million compared to $14.7 million for the year ended December 31, 2016. The increase of $0.6 million relates to our refined products and was primarily driven by an increase in butane blending sales pricing at our Caddo Mills for $1.2 million offset by a decrease in butane blending volumes sold at our North Little Rock terminal facility for $0.6 million.

Services Revenue. Services revenue for the year ended December 31, 2017, was $50.2 million compared to $51.0 million for the year ended December 31, 2016. The decrease of $0.8 million was primarily attributable to a $3.6

million reduction in storage and utilization at our Cushing terminal from a new contract with lower storage and rate terms and a $0.5 million decrease in throughput revenue at our North Little Rock terminal due to the loss of a customer in July 2016, partially offset by a $1.8 million increase in throughput revenues from Caddo Mills facility enhancements and a $1.7 million increase in contracted capacity and related ancillary services as a result of the Harvey terminal expansion.

Cost of Sales. Cost of sales for the year ended December 31, 2017 was $12.9 million compared to $11.6 million for the year ended December 31, 2016. The increase of $1.3 million was primarily due to higher butane costs.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2017 was $38.0 million compared to $42.9 million for the year ended December 31, 2016. The decrease of $4.9 million was primarily attributable to a decrease in Cushing storage, higher operating costs at Harvey and higher butane costs offset by the Harvey expansion and the Caddo Mills facility enhancements discussed above.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2017 were $14.6 million compared to $10.8 million for the year ended December 31, 2016. The increase of $3.8 million was primarily due to a $2.5 million increase in operating costs at our Harvey terminal, driven by $1.0 million increase in repairs and maintenance, contractor services, environmental and related costs directly attributable to the Harvey facility expansion, in addition to $0.6 million for security and supplemental labor.

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

Commodity Sales. Commodity sales for the year ended December 31, 2016 were $14.7 million compared to $10.3 million for the year ended December 31, 2015. The increase of $4.4 million was attributable to an increase in refined products sales related to the addition of butane blending capabilities at our North Little Rock Terminal in the second quarter of 2015.

Services Revenue. Services revenue for the year ended December 31, 2016, was $51.0 million compared to $45.0 million for the year ended December 31, 2015. The increase of $6.0 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at our Harvey terminal of $5.1 million and $0.7 million from increased refined product storage due to additional blending and injection of additives.

Cost of Sales. Cost of sales for the year ended December 31, 2016 was $11.6 million compared to $8.9 million for the year ended December 31, 2015. The increase of $2.7 million was primarily due to an increase in butane blending sales volume.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2016 was $42.9 million compared to $36.1 million for the year ended December 31, 2015. The increase of $6.8 million was primarily attributable to an increase in storage revenue and to a lesser extent margins from refined product sales.

Direct Operating Expenses. Direct operating expenses for the year ended December 31, 2016 were $10.8 million compared to $10.4 million for the year ended December 31, 2015. The increase of $0.4 million was related to liability classified as unit-based compensation.

Liquidity and Capital Resources

Overview

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), or through private and public offerings. In addition, we may seek to raise capital through the issuance of secured and unsecured senior notes. We also have received occasionally cash and liquidity support from our sponsor, ArcLight. 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 four quarters. 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, 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. We plan to finance our growth capital expenditures mainly through additional forms of debt or equity financing, as well as proceeds from the sale of non-core assets.

Changes in natural gas, crude oil, NGL and condensate prices and the terms of our contracts may 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. In the past, 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, see the information provided under Part II, Item 7A of this Annual Report, under the caption 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, 2017, we have not been required to post collateral with our counterparties.

AMID Credit Agreement

On March 8, 2017, we entered into the 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 or 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 customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion.

For the years ended December 31, 2017 and 2016, the weighted average interest rate on borrowings under our Credit Agreement and the JPE Revolver (as defined below) was approximately 4.96% and 4.29%, respectively. At December 31, 2017 and December 31, 2016, letters of credit outstanding under the Credit Agreement were $24.1 million and $7.4 million, respectively. As of December 31, 2017, we had approximately $697.9 million of borrowings, $24.1 million of letters of credit outstanding under the Credit Agreement and approximately $48.0 million of available borrowing capacity which can be increased up to $178.0 million, conditional upon compliance with future covenants.

As of December 31, 2017, we were in compliance with the covenants included in the Credit Agreement. As of December 31, 2017, our consolidated total leverage ratio was 5.23, our consolidated secured leverage ratio was 3.29 and our interest coverage ratio was 3.62. 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. If required, ArcLight, which controls the General Partner of the Partnership, has confirmed its intent to provide financial support for the Partnership to maintain compliance with the covenants contained in the Credit Agreement through April 10, 2019. See Note 14 - Debt Obligations, in Part II, Item 8 of this Annual Report.

We use the term "revolving credit facility" or "Credit Agreement," to refer to our First Amended and Restated Credit Facility and to our Second Amended and Restated Credit Facility, as the context may require.

JPE Revolver

JPE had a $275.0 million revolving loan, which included a sub-limit of up to $100.0 million for letters of credit with Bank of America, N.A. (the "JPE Revolver"). The JPE Revolver was scheduled to mature on February 12, 2019, but on March 8, 2017, in connection with the closing of the JPE Merger, the $199.5 million outstanding balance of the JPE

Revolver was paid off in full and terminated. For the years ended December 31, 2017 and 2016, the weighted average interest rate on borrowings under the JPE Revolver was approximately 2.85% and 2.82%, respectively.

8.50% Senior Unsecured 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 $300 million aggregate principal amount of their 8.50% Senior Notes due 2021 (the "8.50% Senior Notes"). 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 $291.3 million in proceeds, after deducting the initial purchasers' discount of $6.0 million and $2.7 million of debt issuance costs. This amount was deposited into escrow pending completion of the JPE Merger and is included in Restricted cash-long term on our consolidated balance sheet as of December 31, 2016.

The 8.50% Senior 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 conditions related thereto, the proceeds were used to repay and terminate the JPE Revolver and reduce borrowings under our Credit Agreement.

On December 19, 2017, the Issuers completed the issuance and sale of an additional $125 million in aggregate principal amount of 8.50% Senior Notes (the “Additional Issuance”), net of issuance cost of approximately $3.0 million. The Additional Issuance was 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.

The 8.50% Senior Notes will mature on December 15, 2021 and interest on the Additional Issuance will accrue from December 15, 2017. Interest on the 8.50% Senior Notes is payable in cash semiannually in arrears on each June 15 and December 15, with interest payable on the Additional Issuance commencing June 15, 2018. Interest will be payable to holders of record on the June 1 and December 1 immediately preceding the related interest payment date, and will be computed on the basis of a 360-day year consisting of twelve 30-day months. Pursuant to the registration rights agreements entered into in connection with the issuances of the 8.50% Senior Notes, additional interest on the 8.50% Senior Notes accrues at 0.25% per annum for the first 90-day period following December 23, 2017 and by an additional 0.25% per annum with respect to each subsequent 90-day period, up to a maximum additional rate of 1.00% per annum over 8.50%, until we complete an exchange offer for the 8.50% Senior Notes. See Note 14 - Debt Obligations in Part II, Item 8 of this Annual Report, for further discussion of the 8.50% Senior Notes.

3.77% Senior Secured Notes

On September 30, 2016, Midla Financing (“Midla Financing”) American Midstream (Midla) LLC (“Midla”), and MLGT (together with Midla, the “Note Guarantors”) entered into the 3.77% Senior Note Purchase and Guaranty Agreement (the “Note Purchase Agreement”) with the purchasers party thereto (the “Purchasers”). Pursuant to the Note Purchase Agreement, Midla Financing issued and sold $60.0 million in aggregate principal amount of 3.77% Senior Notes (non-recourse) due June 30, 2031 (the “3.77% Senior Notes”) to the Purchasers, which bear interest at an annual rate of 3.77% to be paid quarterly. The average quarterly principal payment is approximately $1.1 million. Principal on the 3.77% Senior Notes will be paid on the last business day of each fiscal quarter end which began June 30, 2017. The 3.77% Senior Notes are payable in full on June 30, 2031. 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. The 3.77% Senior Notes are non-recourse to the Partnership.

In connection with the Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing’s obligations under the Note Purchase Agreement. Also, Midla Financing and the Note Guarantors granted a security interest in substantially all of their tangible and intangible personal property, 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.

Net proceeds from the 3.77% Senior Notes are restricted and have been be used (1) to fund project costs incurred in connection with (a) the construction of the Midla-Natchez Line (b) the retirement of Midla’s existing 1920’s vintage pipeline (c) the move of our Baton Rouge operations to the MLGT system, and (d) the reconfiguration of the DeSiard compression system and all related ancillary facilities, (2) to pay transaction fees and expenses in connection with the issuance of the 3.77% Senior Notes, and (3) for other general corporate purposes of Midla Financing. See Note 14 - Debt Obligations, in Part II, Item 8 of this Annual Report, for further discussion of the 3.77% Senior Notes.

Acquisition Support and Reimbursement

During 2017, an affiliate of ArcLight agreed and provided distribution support of $34.8 million pursuant to the support agreement that was executed in conjunction with the JPE Merger. In March 2018, an affiliate of ArcLight agreed to provide quarterly capital contributions, commencing with the quarter ending March 31, 2018 and ending with respect to the quarter ending September 30, 2018, in connection with the temporary curtailment of production flows at Delta House in the fourth quarter of 2017. The amount of the capital contributions will be agreed, up to the difference between the amount of each quarterly cash distribution received by us on account of our interest in Delta House and the amount of the corresponding quarterly cash distribution expected to be received if production flows to Delta House had not been not curtailed.

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 to a certain extent 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 was $16.2 million at December 31, 2017, compared with a working capital deficit of $16.4 million at December 31, 2016.

Cash Flows

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

	For the Years Ended December 31, 2017		
	2017	2016	2015
Net cash provided by (used in):			
Operating activities	$14,986	$90,639	$86,978
Investing activities	252,310	(564,504)	(250,771)
Financing activities	(264,180)	477,544	161,956

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Operating Activities. Net cash provided by operating activities was $15.0 million for the year ended December 31, 2017, compared to $90.6 million for the year ended December 31, 2016. The decrease of $75.7 million in cash flows from operating activities resulted primarily from an increase in net loss of $62.8 million, excluding the $194.6 million of impairment charges, the $36.0 million MPOG acquisition gain and $51.4 million gains on sale of assets and business recorded in 2017; as well as an increase in the change in operating assets and liabilities of $18.0 million.

Investing Activities. Net cash provided by investing activities was $252.3 million for the year ended December 31, 2017, compared to a use of funds of $564.5 million for the year ended December 31, 2016. The increase of cash flows from investing activities resulted primarily from the release of approximately $299.1 million in restricted cash in March 2017 that was recorded since the end of 2016 and held in escrow, the net proceeds from the sale of our Propane Business of $168.6 million and lower net Acquisitions/Investments and Additions of $88.9 million in 2017, partially offset by lower distributions from unconsolidated affiliates return of capital for $15.1 million.

Financing Activities. Net cash used by financing activities was $264.2 million for the year ended December 31, 2017, compared to net cash provided by financing activities of $477.5 million for the year ended December 31, 2016. The decrease in cash flows from financing activities was due primarily to additional net pay downs on our Credit Agreement of $391.5, lower proceeds from our senior notes of $228.0 million, distributions to our General Partner due to our common control transactions for $86.3 million and the redemption of our Series D Units of $34.5 million, including distributed accrued PIK, partially offset by $44.3 million related to our General Partner’s contributions.

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

Operating Activities. Net cash provided by operating activities was $90.6 million for the year ended December 31, 2016 , compared to $87.0 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 $3.6 million mainly driven by a reduction in net loss of $18.3 million, excluding the $148.5 million goodwill impairment charge recorded in 2015, offset by a decrease in the change in operating assets and liabilities of $10.1 million.

Investing Activities. Net cash used in investing activities was $564.5 million for the year ended December 31, 2016, compared to $250.8 million for the year ended December 31, 2015. Cash used in investing activities for the year ended December 31, 2016 increased by $313.7 million period over period primarily due to the change in restricted cash of $325.6 million as a result of the issuance of our 8.50% Senior Notes and our 3.77% Senior Notes and an increase in investments in unconsolidated affiliates specifically for our interests in the Emerald Transactions and additional interests in Delta House Investment of $84.5 million.

These increases were partially offset by a $60.2 million decrease in capital expenditures and $30.5 million of higher cash distributions received from investments in unconsolidated affiliates as a return of capital.

Financing Activities. Net cash provided by financing activities was $477.5 million for the year ended December 31, 2016, compared to net cash provided by financing activities of $162.0 million for the year ended December 31, 2015. Cash provided by financing activities for the year ended December 31, 2016 increased by $315.5 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 , partially offset by lower borrowings primarily on our revolving credit agreements of $46.2 million.

Distribution to our unitholders

During the year ended December 31, 2017, we paid a total of approximately $89.4 million of distributions to our unitholders. This was made possible primarily by $15.0 million of cash generated from operating activities, and approximately $90.8 million of distributions relating to our unconsolidated affiliates.

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, 2017, our material off-balance sheet arrangements and transactions included operating lease arrangements and service contracts. 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. At December 31, 2017, our off-balance sheet arrangements totaled $163.7 million.

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. 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.

For the year ended December 31, 2017, capital expenditures totaled $117.1 million, including expansion capital expenditures of $105.4 million, maintenance capital expenditures of $8.9 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 $2.8 million. For the year ended December 31, 2016, capital expenditures totaled $147.8 million, including expansion capital expenditures of $137.3 million, maintenance capital expenditures of $6.8 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. Of these capital expenditures amounts, $3.1 million and $3.5 million for the year ended December 31, 2017 and 2016, respectively, were incurred for the Propane Business that we disposed on September 1, 2017, as discussed in Note 4 - Dispositions, in Part II, Item 8 of this Annual Report.

Integrity Management

Certain operating assets require an ongoing integrity management program which is associated high consequence areas ("HCA") that require on-going testing pursuant to the U.S. Department of Transportation ("DOT") regulations. These DOT regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle, which varies from asset to asset and different segments within those asset areas and is date-stamped from the day the energized baseline is established for each operating asset. Our total program addresses approximately 112 HCA as of December 31, 2017. We expect to incur approximately $2.0 million annual cost in integrity management testing expenses. The amount may increase as our HCA mileage may increase through future acquisitions.

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, 2018, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per American Midstream common unit for the fourth quarter ended December 31, 2017, or $1.65 per common unit on an annualized basis. The cash distribution was paid on February 14, 2018, to unitholders of record as of the close of business on February 7, 2018.

Contractual Obligations

The Partnership had the following non-cancelable contractual commitments as of December 31, 2017:

Contractual Obligations	Payments due by period						
	Total	Within Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-Term Debt Obligations							
3.77% Senior Notes	$58,324	$807	$2,233	$2,299	$4,430	$4,579	$43,976
8.50% Senior Notes[1]	425,000	—	—	—	425,000	—	—
Revolving Credit Agreements	697,900	—	697,900	—	—	—	—
3.97% Senior Secured Notes	32,025	1,755	1,805	1,852	1,900	1,952	22,761
Capital Lease Obligations[4]	95	95	—	—	—	—	—
Operating Lease Obligations[3]	33,759	5,263	4,878	3,385	2,906	2,058	15,269
Asset Retirement Obligation[2]	72,610	6,416	—	—	—	—	66,194
Other Long-Term Liabilities Reflected on the Registrant's Balance Sheet under GAAP	129,948	6,853	2,317	2,356	2,361	2,401	113,660
Total	$1,449,661	$21,189	$709,133	$9,892	$436,597	$10,990	$261,860

[1] Upon closing of the JPE Merger, the proceeds from the 8.50% Senior Notes were used to repay the JPE Credit Agreement. On December 28, 2017, the Partnership issued an additional $125.0 million 8.50% Senior Notes, as discussed in Note 14 - Debt Obligations.
[2] In certain cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the ARO. In such cases, the ARO 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.
[3] Represents our commitment to certain long-term services contracts.
[4] Not including sublease income of $2.3 million.

Impact of Seasonality

Results of operations in our Natural Gas Transportation Services 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 Natural Gas Transportation Services segment during the period from October to March compared to other times of the year. We generally do not experience seasonality in our Gas Gathering and Processing Services and Terminalling Servicing segments.

The volume of product that is handled, transported, throughput or stored in our refined products terminals is directly affected by the level of supply and demand in the wholesale markets served by our terminals. Overall supply of refined products in the wholesale markets is influenced by the absolute prices of the products, the availability of capacity on delivering pipelines and vessels, fluctuating refinery margins and the market's perception of future product prices. Although demand for gasoline typically peaks during the summer driving season, which extends from April to September, and declines during the fall and winter months, most of the revenues generated at our refined products terminals do not experience any effects from such seasonality. However, the butane blending operations at our refined products terminals are affected by seasonality because of federal regulations governing seasonal gasoline vapor pressure specifications. Accordingly, we expect that the revenues we generate from butane blending will be highest in the winter months and lowest in the summer months.

The butane blending operations at our refined products terminals are affected by seasonality because of federal regulations governing seasonal gasoline vapor pressure specifications. Accordingly, we expect that the revenues we generate from butane blending will be highest in the winter months and lowest in the summer months.

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 as well as the 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. 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.

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 one-step goodwill impairment test. If the one-step goodwill impairment test indicates that the goodwill is impaired, an impairment loss is recorded, which is the difference between carrying value and fair value.

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 5 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.

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 onshore 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.

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. See discussion regarding the new revenue recognition standard, effective January 1, 2018 in Note 2 - New Accounting Pronouncements, Part II, Item 8 of this Annual Report.

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 forecast transactions and the level of hedging activity executed.

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 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, refer to Note 2 - Recent Accounting Pronouncements, Part II, Item 8 of this Annual Report.

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

Overview

We are exposed to the impact of market fluctuations in the prices of natural gas, crude oil, NGLs and condensate in our Gas Gathering and Processing Services 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, see 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.

Commodity Price Risk per Segment

- Gas Gathering and Processing segment. We purchase and take title to a portion of the NGLs that we sell, which may expose us to changes in the price of NGLs in our sales markets. We manage this commodity price risk by limiting our net open positions and through the concurrent purchase and sale of like quantities of NGLs that are intended to lock in positive margins based on the timing, location or quality of the crude oil purchased and delivered.

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- Liquid Pipelines and Services segment. We purchase and take title to a portion of the crude oil that we sell, which may expose us to changes in the price of crude oil in our sales markets. We manage this commodity price risk by limiting our net open positions and through the concurrent purchase and sale of like quantities of crude oil that are intended to lock in positive margins based on the timing, location or quality of the crude oil purchased and delivered.

- Terminalling Services segment. We sell excess volumes of refined products and our gross margin could be impacted by changes in the market prices for these sales. We may execute forward sales contracts or financial swaps to reduce the risk of commodity price changes in this segment.

- Natural Gas Transportation Services and Offshore Pipelines and Services segments. We do not take title to the products we transport and therefore have no direct commodity price exposure.

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 natural gas, NGL and crude oil exposure.

We have entered into short term contracts in 2017 to hedge crude oil and NGL exposure and they had all expired as of December 31, 2017. We also have entered into contracts to hedge a portion of our NGL and crude oil exposure in 2018.

As of December 31, 2017, 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.

Interest Rate Risk

Overview

Our revolving credit facility bears interest at a variable rate and exposes us to interest rate risk. From time to time, we may use certain derivative instruments to hedge our exposure to variable interest rates. For the year ended December 31, 2017, 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 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. We do not hold or purchase financial instruments or derivative financial instruments for trading purposes.

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.

As of December 31, 2017, we had a combined notional principal amount of $550.0 million of variable to fixed interest rate swap agreements. As of December 31, 2017, the maximum length of time over which we have hedged a portion of our exposure due to interest rate risk is through December 31, 2022.

Sensitivity Analysis

Based on our unhedged interest rate exposure to variable rate debt outstanding as of December 31, 2017, a hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $1.5 million for the year ended December 31, 2017.

Item 8. Financial Statements and Supplementary Data

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

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures 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, 2017 as a result of the material weaknesses in our internal control over financial reporting described below.

Despite the material weaknesses, 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.

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 makes 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, under the supervision of the principal executive officer and principal financial officer of our General Partner, assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2017, based on criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment identified material weaknesses in our internal control over financial reporting. 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 Partnership’s annual or interim financial statements will not be prevented or detected on a timely basis. As a result of these material weaknesses, management has concluded that our internal control over financial reporting was not effective as of December 31, 2017.

Management has identified the following control deficiencies that constituted material weaknesses in our internal control over financial reporting as of December 31, 2017:

We did not maintain an effective control environment as we lacked sufficient oversight of activities related to our internal control over financial reporting and had an insufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with our financial reporting requirements. This material weakness contributed to additional material weaknesses, as the Partnership did not design and maintain effective controls over: verifying that complex, non-routine transactions were recorded appropriately, which such control deficiency resulted in out-of-period adjustments recorded to the income statement in the fourth quarter of 2016 and a revision to the 2015 balance sheet and cash flows; all financial statement assertions of revenue and receivables, specifically the review of the accounting for certain contracts, the review that price, volume and other key contractual terms used to record revenue are consistent with the terms of arrangement and the review that revenue is recorded in the proper period, which such control deficiency resulted in immaterial adjustments to the 2017 consolidated financial statements; all financial statement assertions related to acquisitions and divestitures, specifically verifying the existence, rights and obligations associated with assets acquired and liabilities assumed, reviewing the valuation of the purchase price allocation and reviewing the completeness and accuracy of related disclosures, which such control deficiency resulted in immaterial adjustments to the 2017 consolidated financial statements; the period-end financial reporting process, specifically the review of account reconciliations and financial statement analyses to support the completeness and accuracy of the consolidated financial statements and disclosures, which such control deficiency resulted in immaterial adjustments to the 2017 consolidated financial statements; and the accuracy and valuation of asset retirement obligations, goodwill, other intangible assets and finite-lived assets, specifically the review of the model, data, assumptions and calculations used in determining the estimated asset retirement obligation and in impairment tests, and the related identification of changes in events and circumstances that indicate it is more likely than not that an impairment indicator has occurred, which such control deficiency resulted in adjustments to the accounting for asset retirement obligations and impairments in goodwill, other intangible assets and finite-lived assets for the year ended 2017. Additionally, these material weaknesses could result in a misstatement of substantially all of the financial statement accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

Additionally, we did not maintain effective controls over certain information technology ("IT") general controls for a significant application used in the preparation of our financial statements. Specifically, we did not maintain user access controls to ensure appropriate segregation of duties and that adequately restrict user and privileged access to the financial application, programs, and data to appropriate Partnership personnel. These IT deficiencies did not result in a material misstatement to the financial statements, however, the deficiencies, when aggregated, could impact our ability to maintain effective segregation of duties, as well as maintain effective IT-dependent controls (such as automated controls that address the risk of a material misstatement to one or more assertions, along with the IT controls and underlying data that support the effectiveness of system-generated data and reports), which could result in misstatements of substantially all of the financial statement accounts and disclosures, resulting in a material misstatement to the annual or interim consolidated financial statements that otherwise would not be prevented or detected.

On March 8, 2017, we completed the acquisition of JPE. As a result, management excluded JPE from its assessment of internal control over financial reporting. JPE represents approximately 21.9% of the total assets and 51.4% of net revenues of the related financial statement amounts as of and for the year ended December 31, 2017, respectively.

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, 2017, as stated in their report included on page F-1 of this Annual Report.

Material Weakness Remediation

At December 31, 2016, we identified a material weakness in our internal controls over the level of accounting knowledge, expertise and training commensurate with our financial reporting requirements. This material weakness was not remediated at December 31, 2017. Management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weaknesses identified herein. Specifically, we are taking numerous steps that we believe will address the underlying causes of the material weaknesses, primarily through the hiring of additional personnel with expertise in technical accounting, financial reporting and internal controls, the enhancement of our training programs, the enhancement of our controls and internal review procedures and the implementation and integration of adequate information technology systems.

While plans have been made to enhance our internal control over financial reporting relating to the material weaknesses, management is still in the process of implementing and testing these processes and procedures and additional time is required to complete implementation and to assess and ensure the sustainability of these procedures. Management believes these actions will be effective in remediating the material weaknesses described above and management will continue to devote significant time and attention to these remediation efforts. However, the material weaknesses cannot be considered remediated until the applicable remediated controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

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, 2017 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 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 as Exhibits 32.1 and 32.2.

Item 9B. Other Information

The Partnership discloses the following pursuant to Item 2.06 of Form 8-K:

In the course of the preparation, review and audit of the financial statements required to be included in this Annual Report, management determined that certain impairments to property, plant and equipment and to goodwill were probably required under general accepted accounting principles applicable to the Partnership. As the Partnership worked to finalize the total amount of such impairments, on or about April 4, 2018, management concluded its impairment analysis and determined that such impairments would be material. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" in Part II, Item 7 of this Annual Report and Note 9 - Property, Plant and Equipment, Net and Note 10 - Goodwill and Intangible Assets, Net, both in Part II, Item 8 in this Annual report for additional information. The Partnership does not expect that these impairments will result in any current or future cash expenditures.

The Partnership discloses the following pursuant to Item 3.01 of Form 8-K:

On April 3, 2018, the Partnership received an expected notice from the NYSE stating that the Partnership is not in compliance with the NYSE's continued listing requirements under the timely filing criteria outlined in Section 802.01E of the NYSE Listed Company Manual due to the delay in filing this Annual Report. The NYSE informed the Partnership that, under the NYSE's rules, the Partnership had six months from April 2, 2018 to file this Annual Report with the SEC in order to cure the noncompliance with the NYSE's requirement to timely file all annual and quarterly reports. With the filing of this Annual Report, the Partnership believes it is now in compliance with the NYSE's listing standards.

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 AMID GP Holdings, LLC, a wholly owned subsidiary of Magnolia Infrastructure Holdings, LLC, 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 and oversees risk management activities and a compensation committee ("Compensation Committee").

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.

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 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 Peter A. Fasullo, Donald R. Kendall Jr. and Gerald A. Tywoniuk. Mssrs. Fasullo, Kendall and Tywoniuk serve as the members 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.

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 1, 2018:

Name	Age	Position with American Midstream GP, LLC
Lynn L. Bourdon III	56	Chairman of the Board, President and Chief Executive Officer
Eric T. Kalamaras	44	Senior Vice President and Chief Financial Officer
Rene L. Casadaban	49	Senior Vice President and Chief Operating Officer
Christopher B. Dial	41	Senior Vice President, General Counsel, Chief Compliance Officer, and Corporate Secretary
Louis J. Dorey	62	Senior Vice President - Business Development
Michael J. Croney	39	Vice President, Chief Accounting Officer and Corporate Controller
Edward E. Greene	55	Vice President - Gathering, Processing, and Terminals
Scott M McCrary	48	Vice President - Crude Oil Gathering and Logistics
Ryan K. Rupe	42	Vice President - Natural Gas Services and Offshore Pipelines
Stephen W. Bergstrom	60	Director and Executive Strategy Advisor
John F. Erhard	43	Director
Donald R. Kendall Jr.	65	Director
Daniel R. Revers	56	Director
Peter A. Fasullo	65	Director
Joseph W. Sutton	70	Director
Lucius H. Taylor	43	Director
Gerald A. Tywoniuk	56	Director

Executive officers

Lynn L. Bourdon III was appointed Chairman, President and Chief Executive Officer in December 2015. Previously, 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 Corporation and Valero, and earlier served in various capacities at the Dow Chemical Company. Lynn serves as a member of the Energy Advisory Board with the University of Houston, as a member of the Gas Processing Association and has served on the Propane Education and Research Advisory Council (PERC). Lynn received a Bachelor of Science degree in mechanical engineering from Texas Tech University, an MBA from the University of Houston and is a member of Tau Beta Pi and Pi Tau Sigma.

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 several energy midstream and infrastructure companies where as the principal financial officer he led strategic planning, mergers and acquisitions, and completed over $15 billion of transactions. Mr. Kalamaras served as Chief Financial Officer at Valerus Energy Holdings, Delphi Midstream Partners, and Atlas Pipeline

Partners, LP leading its $2.5 billion financial restructuring. Prior to Atlas Pipeline Partners, he spent a combined 10 years at Wells Fargo and Banc of America Securities providing investment banking and capital markets services to clients in the energy and natural resource industries. Mr. Kalamaras 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 27 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.

Christopher B. Dial, has served as our Senior Vice President, General Counsel and Chief Compliance Officer of our General Partner since January 2018. Prior to his appointment with the General Partner, Mr. Dial was the General Counsel of Susser Holding II, LP. Prior to joining Susser, Mr. Dial spent over eight years in a number of roles, most recently as Associate General Counsel and Corporate Secretary, with both Susser Holdings Corporation, a publicly traded Fortune 500 convenience retailer, and Sunoco, LP, a master limited partnership formed in 2012 out of legacy Susser Holdings fuel distribution assets. Mr. Dial began his career as an Associate Attorney for Andrews Kurth, LLP where he primarily represented master limited partnerships and other energy industry clients on a variety of corporate, capital markets and other transactional matters. Chris holds a Juris Doctor from the University of Houston Law Center and a Bachelor of Arts in Economics from Southwestern University.

Louis J. Dorey has served as Senior Vice President of Business Development since joining American Midstream LP, 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 interim CFO. Mr. Dorey was employed by Dynegy Inc. from 1997 to 2002 where he held various positions including Vice President of Strategy and Planning for Power Assets Group, President of Retail and Wholesale Marketing, and Interim CFO. From 1991 to 1997, Mr. Dorey was employed by Destec Energy Inc. He served as the Vice President of Mergers and Acquisitions and completed various acquisitions and led the sale of Destec Energy Inc. to Dynegy Inc. Mr. Dorey has participated in over $5 billion of transactions including mergers, acquisitions and development transactions, managed five regional wholesale marketing offices, a national retail marketing group, and participated in the closing and integration of three public mergers. He earned a Bachelor of Business Administration from the University of Oklahoma and a Juris Doctorate from the University of Texas, Austin.

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.

Scott M. McCrary has served as Vice President - Crude Oil Gathering and Logistics since joining American Midstream in September of 2017. Most recently, Mr. McCrary served as Vice President - Crude Supply and Trading for Delek US Holdings, Inc. There he was responsible for all aspects of crude supply and trading, including building a lease crude oil team and business. Prior to Delek, he served as Vice President, North American Supply and Trading for Tesoro Refining and Marketing Co. During his tenure he executed several strategic initiatives regarding its North Dakota pipeline system including, various long-term pipeline commitments and rail capabilities, expanded the companies trading segment and ensured the companies refining network remained supplied with domestic crude oil. Prior to Tesoro, Mr. McCrary was Manager Refinery Supply at Frontier Refining and Marketing Company, where he was responsible for all Domestic and International Crude Supply and Trading for Frontier’s 110,000 bpd El Dorado Refinery. This included their Spearhead Pipeline Commitment’s and Cushing Tankage requirements. Prior to Frontier, he worked in various Crude Supply, Trading and Transportation jobs at Citgo Refining in Tulsa, Dallas and Houston. Mr. McCrary has been in the energy industry for over 25 years, with experience in finished product transportation, lease crude oil acquisitions, trading, and refinery supply. He earned a Bachelor of Business Administration in Marketing from Northeastern State University in Oklahoma.

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 Gulf Coast Trading and Gas Scheduling. 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.

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 and in June 2017, became employed as our Executive Strategy Advisor. 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 17 years of energy finance and private equity experience. 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 Partners (NYSE: BPL) and its publicly traded General Partner, Buckeye GP Holdings. We believe that Mr. Erhard's 17 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 serves as a director of Tangent Energy Solutions, SkyCentrics and he also served as a director and audit committee chairperson of SolarCity (and chair of the Special Committee) and Stream Energy. In addition, Mr. Kendall serves in various capacities at not-for-profit organizations, including The Jane Goodall Institute, The Houston Zoo Conservation Committee, Mar Alliance, Bat Conservation International 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 co-founder of ArcLight and has 26 years of energy finance and private equity experience. Mr. Revers manages the ArcLight office 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. 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 Trustees of The Rivers School. 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' 26 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. Mr. Sutton is the founder and owner of Sutton Ventures Group, LLC, an energy investment firm that he founded, which has investments in many energy endeavors. One of his early successes was as a founder of Millennium Midstream, which was later purchased by Eagle Rock. 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 and financial 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 17 years of experience in energy finance, private equity 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 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. In addition, Mr. Taylor has experience in the MLP sector and currently serves on the board of directors of the general partner of TransMontaigne Partners, L.P. (NYSE: TLP). We believe that Mr. Taylor's 17 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). In February 2018, Mr. Tywoniuk was appointed Chairman of WMLP. 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 Professional Accountant (Chartered Accountant). Mr. Tywoniuk has 35 years of experience in accounting and finance, including service as a member of the board of directors of four public companies, Chief Financial Officer of three public companies, Vice President/Controller of another 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, 2017, 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 Forms 4 for Edward E. Greene on April 13, 2017, May 4, 2017 and May 4, 2017; and
- Late filing of a Form 4 for Ryan K. Rupe on March 20, 2018

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, 2017:

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
Rene L. Casadaban	Senior Vice President and Chief Operating Officer (appointed March 2017)
Louis J. Dorey	Senior Vice President - Business Development
Ryan K. Rupe	Vice President - Natural Gas Services and Offshore Pipelines

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.
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, 2017.

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. Management, on behalf of the compensation committee, engaged the services of Mercer, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for the executive officers for 2017. We consider Mercer to be independent of the Partnership and therefore, the work performed by Mercer does not create a conflict of interest. The Mercer study was based on compensation for a group of peer companies with similar operations obtained from public documents as well as multiple survey sources, including the 2016 Mercer Benchmark Database and the 2016 Mercer Total Compensation Survey for the Energy Sector.
During 2017, the Compensation Committee discussed executive compensation issues at several meetings, and the Compensation Committee expects to hold additional executive compensation-related meetings in 2018 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 was (and will continue to be) established by the Compensation Committee. In addition, the Compensation Committee made (and will continue to make) its decisions with respect to any awards under the LTIP and recommend awards to the Board. Our Chief Executive Officer provides 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, see "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: Buckeye Partners LP, Crestwood Equity Partners LP, DCP Midstream,Partners LP, Enable Midstream Partners LP, Enlink Midstream Partners LP, Genesis Energy LP, Magellan Midstream Partners LP, Nustar Energy LP, SemGroup Corporation, Southcross Energy Partners LP, Summit Midstream Partners LP and Targa Resources Corp.

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.	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.	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. 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.	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 through our 401(k) plan.	Provide our executive officers and other 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.

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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 Board, upon the recommendation of 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 Board upon the recommendation of the Compensation Committee. Annual base salary adjustments, if any, for the other executive officers will be determined by the Board upon the recommendation of the Compensation Committee, taking into account input from the Chief Executive Officer.

The Compensation Committee approved the following base salaries for 2017 for the named executive officers as provided in the table below.

Name	Base Salary at the end of 2017
Lynn L. Bourdon III	$500,000
Eric T. Kalamaras	305,000
Rene L Casadaban	305,000
Louis J. Dorey	275,000
Ryan K. Rupe	250,000

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 Board upon the recommendation of the Compensation Committee. Annual cash incentive awards, if any, for the other executive officers are determined by the Board upon the recommendation of the Compensation Committee taking into account input from the Chief Executive Officer.

We 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 Board upon the recommendation 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 recommendations. 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 2017 for all of the executive officers are set forth in the table below. Target bonus amounts were changed to align with our new strategy to ensure that each level of executive management was operating with the same targets.

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 2017;
- 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 Board upon the recommendation of the Compensation Committee, determined to award the incentive bonus amounts, which were paid in cash, set forth in the table below to our named executive officers for performance in 2017.

Name	2017 Target Bonus	2017 Bonus Earned
Lynn L. Bourdon III	$500,000	$500,000
Eric T. Kalamaras	228,750	290,000
Rene L. Casadaban	228,750	275,000
Louis J. Dorey	206,250	230,000
Ryan K. Rupe	187,500	210,000

For 2017, 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.
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.

Performance Based Awards. In November 2017, the Board of Directors of our General Partner approved the grant of performance based awards ("PSUs") to create a highly accretive, long-term retention tool to key personnel whom management expects to drive performance over the long-term. The awards will vest on November 20, 2022, subject to acceleration in certain circumstances.

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 each vested phantom units with 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.

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 2017, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 6% 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 2018, 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 Mr. Bourdon 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, 2017
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, 2017.

	Year	Salary	Bonus	Unit Awards (1)	All Other Compensation	Total Compensation
Lynn L. Bourdon III (2)	2017	$500,000	$500,000	$1,105,049	$ 16,154	$ 2,121,203
Chairman of the Board, President and Chief Executive Officer	2016	500,000	750,000	598,812	15,838	1,864,650
	2015	32,692	—	1,501,952	—	1,534,644
Eric T. Kalamaras (3)	2017	300,000	290,000	1,285,341	73,658	1,948,999
Senior Vice President and Chief Financial Officer	2016	137,019	92,000	359,730	240,189	828,938
	2015	—	—	—	—	—
Rene L. Casadaban (4)	2017	227,577	275,000	1,526,890	8,681	2,038,148
Senior Vice President and Chief Operating Officer	2016	—	—	—	—	—
	2015	—	—	—	—	—
Louis J. Dorey (5)	2017	275,000	230,000	920,267	14,644	1,439,911
Senior Vice President - Business Development	2016	—	—	—	—	—
	2015	—	—	—	—	—
Ryan K. Rupe	2017	250,000	210,000	823,701	—	1,283,701
Vice President Commercial Operations	2016	250,000	160,000	243,727	—	653,727
	2015	—	—	—	—	—

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(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, unit options award granted, and the performance unit awards in each of the three years ended December 31, 2017. 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. See the table below for these calculations. For additional information on the assumptions used to calculate the grant date fair value of equity incentive awards, refer to Note 18 - Long-Term Incentive Plan of this Annual Report, incorporated herein by reference.

2017 Phantom Unit Awards

	Grant date value of phantom units before distributions(6)	Present value of distributions	Grant date value of phantom units less distributions
Lynn L. Bourdon III	$1,510,100	$405,051	$1,105,049
Eric T. Kalamaras *	$430,381	$115,440	$314,941
Rene L. Casadaban *	$684,830	$183,690	$501,140
Louis J Dorey *	$263,015	$70,548	$192,467
Ryan K. Rupe *	$213,935	$57,383	$156,552

* Does not include unit options or performance units awarded.

(2) Other compensation includes $16,154 of matching contributions that we made on account of employee contributions under our 401(k) Savings Plan.

(3) Other compensation includes $57,694 of relocation expenses and $15,964 of matching contributions that we made on account of employee contributions under our 401(k) Savings Plan.

(4) Other compensation includes $8,681 of matching contributions that we made on account of employee contributions under our 401(k) Savings Plan.

(5) Other compensation includes $14,644 of matching contributions that we made on account of employee contributions under our 401(k) Savings Plan.

(6) The market value of phantom units at grant date of April 3, 2017 was calculated based on a share value of $14.95 multiplied by the number of phantom units awarded.

Grants of Plan-Based Awards for 2017

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				
04/3/2017 Grant	101,010	Phantom Units		$1,105,049
Eric T. Kalamaras				
04/3/2017 Grant	28,788	Phantom Units		314,941
11/20/17 Grant	80,000	PSU		970,400
Rene L. Casadaban				
04/3/2017 Grant	30,808	Phantom Units		337,040
04/3/2017 Grant	15,000	Phantom Units		164,100
04/3/2017 Grant [2]	15,000	Options	14.85	55,350
11/20/17 Grant	80,000	PSU		970,400
Louis J. Dorey				
04/3/2017 Grant	17,593	Phantom Units		192,467
11/20/17 Grant	60,000	PSU		727,800
Ryan K. Rupe				
04/3/2017 Grant	14,310	Phantom Units		156,551
11/20/17 Grant	55,000	PSU		667,150

(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 18 - Incentive Compensation of this Annual Report, which is incorporated herein by reference.

(2) In April 2017, the Board of Directors of our General Partner approved the grant of an option to purchase 15,000 common units of the Partnership at an exercise price per unit equal to $14.85. The options will vest over four years at a rate of 25% per year. The options expire on April 3, 2027, or ten years from the date of grant.

Employment Agreements with Named Executive Officers ("NEO")

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 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. Bourdon's employment agreement also provides for, among other things, the payment of severance benefits under certain circumstances. See 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, 2017

The following table provides information regarding outstanding equity-based awards held by the named executive officers as of December 31, 2017. All such equity-based awards consist of phantom units, performance units and unit options granted under the LTIP.

	Unit Awards						
Name	Number of Unvested Phantom Awards (6)	Market Value (1)	Number of Unexercised Option Awards	Option Exercise Price	Number of Unvested Performance Awards	Grant Date Fair Value of Performance Awards ($) (5)	
Lynn L. Bourdon III (2)	433,053	$ 5,781,258	200,000	$ 7.50	—	$	—
Eric T. Kalamaras (3)	68,788	918,320	30,000	$ 12.00	80,000	970,400	
Rene L. Casadaban (4)	45,808	611,537	15,000	$ 14.85	80,000	970,400	
Louis J. Dorey	64,549	861,729	—	—	60,000	727,800	
Ryan K. Rupe	78,183	1,043,743	—	—	55,000	667,150	

(1) The market value of phantom units that had not vested as of December 31, 2017 was calculated based on the fair market value of our Common Units as of December 31, 2017, which was $13.35 multiplied by the number of unvested phantom units. See Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates Equity-Based Awards in Part II, Item 7 of this Annual Report.

(2) In conjunction with the execution of Mr. Bourdon's employment agreement effective December 10, 2015, the Board approved a grant of 200,000 phantom 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) In April 2017, the Board of Directors of our General Partner approved the grant of an option to purchase 15,000 common units of the Partnership at an exercise price per unit equal to $14.85. The options will vest over four years at a rate of 25% per year. The options expire on April 3, 2027, or ten years from the date of grant.

(5) The market value of performance units was calculated based on the grant date fair value of our performance units which was $12.13 multiplied by the number of unvested performance units. A Monte-Carlo pricing model was used to determine the fair value of our performance grants. In November 2017, the Board of Directors of our General Partner approved the grant of performance based awards to create a highly accretive, long-term retention tool to key personnel whom management expects to drive performance over the long-term. The awards will vest on November 20, 2022, subject to acceleration in certain circumstances. See Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies and Estimates Equity-Based Awards and Note 18 - Incentive Compensation in Part II, Item 8 in this Annual Report for additional information.

(6) 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 common units 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.

Units Vested in 2017

The following table shows the phantom unit awards that vested during 2017.

Name	2017 Number of Units Acquired on Vesting	Fair Market Value per Unit Upon Vesting	Value Realized on Vesting (1)
Lynn L. Bourdon III			
02/26/2017 vest	66,021	$ 15.70	$ 1,036,530
Louis J. Dorey			
02/19/2017 vest	3,646	16.20	59,065
02/23/2017 vest	3,499	16.15	56,509
02/26/2017 vest	12,104	15.70	190,033
Ryan K. Rupe			
02/19/2017 vest	2,123	16.20	34,393
02/23/2017 vest	2,565	16.15	41,425
02/26/2017 vest	8,873	15.70	139,306

(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.

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. The employment agreement provides for accelerated vesting of certain equity incentive awards upon Mr. Bourdon's death or disability.

• “Cause” means Mr. Bourdon 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 equity holders; (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 Mr. Bourdon's responsibilities, duties, authority or titles or the assignment to Mr. Bourdon of duties or responsibilities inconsistent with Mr. Bourdon's status and titles as the most senior officer of our General Partner; (ii) assignment of Mr. Bourdon to a principal office located beyond a 30-mile radius of Mr. Bourdon'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, the severance arrangement terminated by its terms on July 11, 2017.

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, 2017:

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]	$5,781,258	$5,781,258	$5,781,258	$5,781,258
	Accelerated vesting of options awards per award agreement [1]	$1,170,000	$1,170,000	$1,170,000	$1,170,000
	Total	$6,951,258	$7,970,128	$8,970,128	$6,951,258
Eric T. Kalamaras	Accelerated vesting of phantom unit awards, option awards and performance unit awards per award agreement	$2,026,820	None	$2,026,820	$2,026,820
Rene L. Casadabani	Accelerated vesting of phantom unit awards, option awards and performance unit awards per award agreement	$1,679,537	None	$1,679,537	$1,679,537
Louis J. Dorey	Accelerated vesting of phantom unit awards and performance unit awards per award agreement	$1,662,729	None	$1,662,729	$1,662,729
Ryan K. Rupe	Accelerated vesting of phantom unit awards and performance unit awards per award agreement	$1,777,993	None	$1,777,993	$1,777,993

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(1) The amounts shown in this row are calculated based on the fair market value of our Common Units which we have assumed were $13.35, which was the closing price of our Common Units on December 31, 2017, multiplied by the number of phantom units that would have vested as of December 31, 2017. The market value of the Option Grant that has not vested as of December 31, 2017 for Mr. Bourdon is $5.85, per Common Unit subject to the option, which is the difference between the closing price of our Common Units on December 31, 2017 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.

Pay Ratio

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, the following disclosure provides the ratio of the annual total compensation of Mr. Bourdon, our President and Chief Executive Officer, to the annual total compensation of the median employee of our general partner. All of our general partner's employees (including executive officers) are dedicated exclusively to the Partnership and our general partner determines the compensation of our Chief Executive Officer and employees.

For 2017, Mr. Bourdon's annual total compensation was $2,121,203, as reported in the Total column of the 2017 Summary Compensation Table included in this Item 11, and the annual total compensation of the median compensated employee was $77,301. Based on this information, the ratio of the annual total compensation of Mr. Bourdon to the median compensated employee for 2017 was to 27:1.

The pay ratio reported above is a reasonable estimate calculated in a manner consistent with the SEC rules based on our payroll and employment records and the methodology described below. For these purposes, using our employee population and payroll register as of December 31, 2017, we identified the median compensated employee by annualizing base salary earned in December 2017 for all employees. To this we added, for all employees, target cash bonus and the estimated 401(k) employer matching for the 2017 performance year.

The SEC’s rules for identifying the median compensated employee and calculating the pay ratio based on that employee’s annual total compensation allow companies to adopt a variety of methodologies, to apply certain exclusions, and to make reasonable estimates and assumptions that reflect their employee populations and compensation practices. As a result, the pay ratio reported by other companies may not be comparable to the pay ratio reported above, as other companies have different employee populations and compensation practices and may utilize different methodologies, exclusions, estimates and assumptions in calculating their own pay ratios.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the Board was comprised of Messrs. Bourdon and Erhard as of December 31, 2017. The Compensation Committee makes compensation recommendations to the full Board 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 2017 on a board of directors or compensation committee of another entity which has employed any of the members of our Board or Compensation Committee.

Compensation of Directors

Director Fees

During 2017, each director who was not an officer or employee of our General Partner received 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 received 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.

The Compensation Committee of the Board, following a review of the compensation of our Board of Directors, recommended to the Board, and the Board approved, the following compensation for each director who is not an officer or employee of our General Partner beginning on January 1, 2018. The compensation was determined by conducting an analysis of compensation paid to non-employee directors by our peer group.
- a $70,000 annual cash retainer;
- a $70,000 annual unit grant;
- a $15,000 retainer paid to the chairman of the Audit Committee;
- a $2,500 cash payment, per transaction, for service rendered as a member of the Conflicts Committee to the Board; and
- a $5,000 cash payment, per transaction, for service rendered as the Chairman of the Conflicts Committee to the Board.

Effective June 1, 2017, Mr. Bergstrom was appointed as the Executive Strategy Advisor to our General Partner. As a result of Mr. Bergstrom’s employment by the General Partner, he is not eligible to receive compensation as a board member. Instead, Mr. Bergstrom’s compensation for his role as Executive Strategy Advisor is at the same level as if he were a non-employee member of the Board. Thus, for 2018, Mr. Bergstrom will be paid an annual salary of $70,000 and will be eligible for an annual unit grant of $70,000. As a result of his employment with the General Partner, Mr. Bergstrom is eligible to participate in the General Partner’s medical, dental, vision, flexible spending accounts, 401(k) retirement plan and the other benefit programs offered to all employees.

Generally, 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 2017

The following table sets forth the compensation paid to our non-employee directors for the year ended December 31, 2017, as described above. The compensation paid in 2017 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(2)	$ 40,750	$ 40,250	$ 40,286	$ 121,286
John F. Erhard	—	—	—	—
Donald R. Kendall Jr.	66,010	66,250	—	132,260
Daniel R. Revers	—	—	—	—
Rose M. Robeson	—	—	—	—

Peter A. Fasullo	77,500	67,500	—	145,000
Joseph W. Sutton	—	—	—	—
Lucius H. Taylor	—	—	—	—
Gerald A. Tywoniuk	86,500	76,500	—	163,000

(1) The amount reported in this column represents the aggregate grant date value of the unit award granted during 2017 based on the annual unit grant mentioned above.

(2) Effective June 1, 2017, Mr. Bergstrom became employed by the Partnership as the Executive Strategy Advisor. Thus, $40,750 of the cash paid to Mr. Bergstrom in 2017 was paid to him as a non-employee director and $40,286 of the cash paid to Mr. Bergstrom in 2017 was paid to him for his service in the role of Executive Strategy Advisor.

Compensation Committee Report

During 2017, 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 2017 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 2017.

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 26, 2018 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.

As of December 31, 2017, our General Partner is owned 77% directly by HPIP and 23% indirectly 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 26, 2018, 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	Percentage of Total Common Units Beneficially Owned on a Fully Converted Basis (8)	
ArcLight Capital Partners, LLC (1)	13,977,709	26.5	%	11,009,729	9,241,642	48.3	%
Swank Capital, LLC (2)	2,379,267	4.5	%	—	—	3.2	%
Oppenheimer Funds, Inc. (3)	6,087,090	11.5	%	—	—	8.1	%
Lynn L. Bourdon III (4)	204,507	*		—	—	*	
Eric T. Kalamaras (4)	—	*		—	—	*	
Christopher B. Dial (4)	—	*		—	—	*	
Louis J. Dorey (4)	38,509	*		—	—	*	
Rene L. Casadaban (4)	—	*		—	—	*	
Ryan K. Rupe (4)	22,120	*		—	—	*	
Daniel R. Revers (1)(2)(4)	13,977,709	26.5	%	11,009,729	9,241,642	48.3	%
John F. Erhard (4)	—	*		—	—	*	
Stephen W. Bergstrom (4)	50,337	*		—	—	*	
Donald R. Kendall Jr. (4)	31,310	*		—	—	*	
Peter A. Fasullo (4)(5)	9,693	*		—	—	*	
Joseph W. Sutton (4)	—	*		—	—	*	
Lucius H. Taylor (4)	—	*		—	—	*	
Gerald A. Tywoniuk (6)	25,713	*		—	—	*	
All directors and executive officers as a group (consisting of 17 persons)	14,372,703	27.2	%	11,009,729	9,241,642	48.8	%

* An asterisk indicates that the person or entity owns less than one percent.

(1) Includes 7,707,571 Series A-1 Convertible Preferred Units ("Series A-1 Units") held by High Point Infrastructure Partners, LLC ("High Point"), convertible into 8,855,999 common units of the Issuer ("Common Units"), which are indirectly owned by Magnolia Infrastructure Partners, LLC ("Magnolia"), 3,302,158 Series A-2 Convertible Preferred Units ("Series A-2 Units") held by Magnolia, convertible into 3,794,180 Common Units, 9,241,642 Series C Convertible Preferred Units ("Series C Units") held by Magnolia Infrastructure Holdings, LLC ("Magnolia Holdings"), convertible into 9,663,061 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 AMID GP Holdings, LLC (GP Holdings"), 618,921 Common Units held by Magnolia and 2,255,754 Common Units held by Busbar II, LLC ("Busbar").

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. GP Holdings is a wholly owned subsidiary of Magnolia Holdings (collectively, Busbar HPIP, Magnolia, Fund V, Fund GP, ArcLight Holdings, ArcLight and GP Holdings 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 October 12, 2017 and the Form 4 filed by the beneficial owner on February 16, 2018.

(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 2,379,367 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 2,379,367 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 2,379,367 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, 2018.

(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 6,087,090 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/A filed by the beneficial owner on February 6, 2018.

(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) Includes 9,693 Common Units held in Fasullo Family Revocable Trust, for which Mr. Fasullo is the trustee.

(6) Includes 20,357 Common Units held in The Gerald Allen Tywoniuk Trust dated June 25, 2010, for which Mr. Tywoniuk is the trustee.

(7) The percentage of units beneficially owned is based on a total of 52,852,752 common units and 11,009,729 Series A Units and 9,241,642 Series C Units, as applicable, outstanding at March 26, 2018.

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 on November 20, 2017. At December 31, 2017, 2016 and 2015, there were

4,134,412; 5,017,528; and 15,484 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

For more information regarding related party transactions, see Note 21 - Related-Party Transactions in Part II, Item 8 of this Annual Report.

As of March 26, 2018, HPIP controlled and owned 77% of the General Partner of the Partnership, and Magnolia Infrastructure Holdings, LLC owned 23% of our General Partner, which indirectly owned an approximate 1.3% General Partner interest in us and all of our incentive distribution rights. HPIP and Magnolia Infrastructure Partners ("MIP") held 7,707,571 Series A-1 Units and 3,302,158 Series A-2 Units, respectively, and controlled 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 7,707,571 Series A-1 Units, MIP (an affiliate of HPIP), as the holder of 3,302,158 Series A-2 Units, and Magnolia Infrastructure Holdings, LLC (an affiliate of HPIP), as the holder of 9,241,642 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. 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.

With respect to the quarter ended June 30, 2016 and for each Quarter thereafter through and including the quarter ended December 31, 2018, in the discretion of the General Partner and upon the consent of Magnolia, the Series C Quarterly Distribution may be paid partially or entirely in a number of Series C PIK preferred units. With respect to the Quarter ending March 31, 2019 and all quarters thereafter, the Series C Quarterly Distributions will be paid entirely in cash.

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 was 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. On October 2, 2017, pursuant to the terms of our Partnership Agreement, we exercised our call right to repurchase all of the 2,333,333 outstanding Series D Units from Magnolia Infrastructure Holdings, LLC, an affiliate of ArcLight, for approximately $34.5 million in cash, which was funded through our existing revolver. After the closing date of such redemption, which occurred on October 2, 2017, there were no more outstanding Series D Units.

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. For further information about the relationship between the General Partner and the Partnership, see Note 21. Related Party Transactions - General Partner in Part II, Item 8 in this Annual Report.
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 in Our General Partner

HPIP controls and owns 77% and Magnolia Infrastructure Holdings, LLC, through its ownership in AMID GP 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 year ended December 31, 2017, our General Partner incurred approximately $0.8 million of costs related to business development compensation that were funded by the Partnership. As of December 31, 2017, the Partnership has been reimbursed for these costs. For the year ended December 31, 2017, our General Partner incurred approximately less than $0.1 million of costs associated with other business development activities. 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"). The Partnership regularly engages in purchases and sales of crude oil and natural gas with CIMA. During fiscal years 2017, 2016 and 2015, the Partnership paid CIMA $5.3 million, $4.3 million and $5.3 million, respectively, and received from CIMA $8.0 million, $3.6 million and $4.7 million in connection with such transactions, respectively.

Dan Revers, a director of our General Partner, indirectly owns in excess of 10% of Consolidated Asset Management Services, LLC, which, through various subsidiaries or affiliates (collectively, "CAMS"), provides pipeline integrity services to the Partnership and subleases an office space from the Partnership. During fiscal years 2017, 2016 and 2015, the Partnership paid CAMS $0.4 million, $0.3 million and $0.6 million, respectively, and received $11 thousand, zero and zero from CAMS, respectively.

Until April 2015, JPE received information and technology support from CAMS Bluewire, an affiliate of CAMS. For the year ended December 31, 2015, JPE paid $132,000 for IT support and consulting services, and for purchases of IT equipment from CAMS Bluewire.

On November 6, 2017, we announced the acquisition and closing of Trans-Union from affiliates of ArcLight for a total consideration of approximately $49.4 million as further described in Note 3 - Acquisitions - Acquisition of Trans-Union Pipeline of Part II, Item 8 of this Annual Report.

On October 30, 2017, we acquired an additional 17.0% equity interest in Destin from an ArcLight affiliate for total consideration of $30.0 million as further described in Item 1 Business - Recent Developments of this Annual Report.

On October 2, 2017, pursuant to the terms of our Partnership Agreement, we exercised our call right to repurchase all of the 2,333,333 outstanding Series D Units from Magnolia Infrastructure Holdings, LLC, an affiliate of ArcLight, for approximately $34.5 million in cash, which was funded through our existing revolver. After the closing date of such redemption, which occurred on October 2, 2017, there were no more outstanding Series D Units. The Series D Units were originally issued on October 31, 2016 in a private placement for $15.00 per unit, less a closing fee of 1.5%, for approximately $34.4 million in net proceeds to the Partnership.

Through several transactions in 2017, 2016 and 2015, the Partnership acquired interests in Delta House from affiliates of ArcLight as further described in Note 3 - Acquisitions - Delta House Investment of Part II, Item 8 of this Annual Report.

On March 8, 2017, we completed the acquisition of JPE, an entity controlled by affiliates of ArcLight as further described in Item 1 Business - Recent Developments of this Annual Report. In connection with this transaction, an affiliate of ArcLight agreed to provide, and provided, $25 million of distribution support for the fiscal year 2017. Separate from this financial support, our General Partner also agreed to absorb $17.6 million corporate overhead expenses, which were incurred by and reimbursed to us in 2017. These support payments are described further in Note 21 - Related-Party Transactions of Part II, Item 8 of this Annual Report.

Pursuant to the acquisition of JPE, an ArcLight affiliate agreed to reimburse JPE for its expenses associated with the transaction. The total amounts reimbursed to JPE, or to AMID following its acquisition of JPE, was $10.6 million for the year ended December 31, 2017, and was treated as a deemed contribution from ArcLight. On April 25 and 27, 2016, the Partnership completed the Emerald Transactions for a total of $225 million and issued the Series C Units and the Series C Warrant, all as further described in Note 3 - Acquisitions - Emerald Transactions of Part II, Item 8 of this Annual Report.

American Midstream Bakken, LLC, a wholly owned, indirect subsidiary of AMID (“AMID Bakken”) purchased one production unit receipt point measuring package and one truck loading/unloading LACT package from Republic Midstream, LLC, an entity controlled by ArcLight, for $0.3 million in September 2015.

JPE performed certain management services for JP Development LP, an entity controlled by ArcLight (“JP Development”). JPE received a monthly fee of $50,000 for these services through 2015 until January 2016. In the year ended December 31, 2015, JPE also performed certain additional services for which it received $0.2 million.

JP Development had a pipeline transportation business that provided crude oil pipeline transportation services to JPE’s discontinued Mid-Continent Business. As a result of utilizing JP Development’s pipeline transportation services during the years ended December 31, 2016 and 2015, JPE incurred pipeline tariff fees of $0.4 million and $6.0 million, respectively.

Effective July 30, 2014, American Midstream Republic, LLC, a wholly owned, indirect subsidiary of AMID (“AMID Republic”), entered into a management services agreement with Republic Midstream, LLC, an entity controlled by ArcLight. Pursuant to the management services agreement, AMID Republic agreed to provide gathering services and perform asset management activities, in addition to any other mutually agreed upon services, on behalf of Republic Midstream in exchange for a monthly fee of $87,088 as well as reimbursement for certain agreed upon expenses and out of scope services. As of December 1, 2015, the monthly fee was reduced to $64,875. The management services agreement terminated according to its terms on September 1, 2017. During fiscal years 2017, 2016 and 2015, the Partnership invoiced and received approximately $1.0 million, $1.3 million and $1.0 million, respectively, pursuant to the terms of the management services agreement.

American Midstream Lavaca, LLC, a wholly owned, indirect subsidiary of AMID (“AMID Lavaca”), in 2015, for administrative convenience, purchased real property and easements that were resold to Republic Midstream. On March 9, 2015, AMID Lavaca transferred easements to Republic Midstream for $1.5 million, the direct cost to AMID Lavaca of acquiring such easements, and received reimbursement of $1.3 million for capital expenditures incurred in respect of such easements, the direct costs to AMID Lavaca of such expenditures.

On April 20, 2013, our general partner entered into a reimbursement agreement with HPIP Gonzales Holdings, LLC, an entity controlled by ArcLight (“HPIP Gonzales”) under which the general partner received reimbursement for general and administrative costs related to the building of a gathering, processing and salt-water disposal system and a monthly management fee of $55,000. AMID stopped invoicing the management fee on August 1, 2015 and no further services were provided under the agreement. During fiscal year 2015, the Partnership invoiced $0.4 million to HPIP Gonzales under the reimbursement agreement.

JPE also performed certain management services for Republic Midstream in exchange for a monthly fee of approximately $75,000. In September 2016, this monthly fee decreased to approximately $40,000 before ceasing in November 2016. For the years ended

December 31, 2016 and 2015, JPE charged fees of $0.7 million and $0.7 million, respectively, to Republic Midstream for these services. During 2016, JPE performed crude transportation and marketing services for Republic Midstream. JPE charged $3.2 million and $3.0 million for the years ended December 31, 2016 and 2015, respectively, for these crude transportation and marketing services.

On February 1, 2016, JPE completed the sale of its crude oil supply and logistics operations in its Mid-Continent region of Oklahoma and Kansas to JP Development in connection with JP Development's sale of its GSPP pipeline assets to a third-party buyer. The sales price was $9.7 million; which included certain adjustments related to inventory and other working capital items.

As a result of JPE's acquisition of the North Little Rock, Arkansas refined product terminal in November 2012, Truman Arnold Companies ('TAC") owned common and subordinated units in JPE. In addition, Mr. Greg Arnold, President and CEO of TAC, was also a director of JPE's general partner and owned a 5% equity interest in JPE's general partner through October 2016. JPE's refined products terminals and storage segment sold refined products to TAC during 2016. For the year ended December 31, 2016, JPE's revenue from TAC was $0.2 million.

JPE's NGL distribution and sales segment also purchased refined products from TAC. For the years ended December 31, 2016 and 2015, JPE paid $1.0 million and $1.1 million, respectively, for refined product purchases from TAC.

During the years ended December 31, 2016 and 2015, JPE's general partner agreed to absorb $9.0 million and $5.5 million of corporate overhead expenses incurred by JPE and not pass such expense through to JPE. JPE received reimbursements for these expenses from its general partner in the quarters subsequent to when they were incurred, which was $7.5 million and $3.0 million for the years ended December 31, 2016 and 2015, respectively. In the first quarter of 2015, certain executive bonuses related to the year ended December 31, 2014 were paid on JPE's behalf by ArcLight. In addition, ArcLight reimbursed JPE for expenses we incurred for the years ended December 31, 2016 and 2015. The total amounts paid on our behalf or reimbursed to us were $2.4 million and $2.6 million for the years ended December 31, 2016 and 2015, respectively, and were treated as deemed contributions from ArcLight.

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, as updated on November 2, 2017, 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.

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,	
	2017	2016
	(in thousands)	
Audit fees and audit related fees [1] [2]	$4,733	$3,958
Tax fees [3]	2,259	943
All other fees [4]	1	4
	$6,993	$4,905

(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 SEC, 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 for additional SEC documents (S-4, S-3, etc.) 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, 2017. 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 time frame.

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(a)(3) Exhibits

Exhibit Number	Exhibit
2.1	Purchase and Sale Agreement 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 (Commission File No. 001-35257) filed on April 29, 2016).
2.2	Purchase and Sale Agreement 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 (Commission File No. 001-35257) filed on April 29, 2016).
2.3	Purchase Agreement 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 (Commission File No. 001-35257) filed on April 29, 2016).
2.4	Agreement and Plan of Merger, 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 (Commission File No. 001-35257) filed on October 24, 2016).
2.5	Agreement and Plan of Merger, dated October 31, 2017 among American Midstream Partners, LP, American Midstream GP, LLC, Southcross Energy Partners, L.P. and Southcross Energy Partners GP, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on November 1, 2017).
2.6	Contribution Agreement, dated October 31, 2017 among American Midstream Partners, LP, American Midstream GP, LLC and Southcross Holdings LP (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on November 1, 2017).
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.2	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 (Commission File No. 001-35257) filed on April 29, 2016).
3.3	Amendment No. 1 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, effective May 1, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on June 22, 2016).
3.4	Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated October 31, 2016 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on November 4, 2016).
3.5	Amendment No. 3 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated March 8, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 8, 2017).
3.6	Composite Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, including Amendment No. 1, Amendment No. 2 and Amendment No. 3 (incorporated by reference to Exhibit 3.19 to the Annual Report on Form 10-K (Commission File No. 001-35257) filed on March 28, 2017).
3.7	Amendment No. 4 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated May 25, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on May 31, 2017).
3.8	Amendment No. 5 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated June 30, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on July 14, 2017).
3.9	

	Amendment No. 6 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated September 7, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on September 11, 2017).
3.10	Amendment No. 7 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated October 26, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on October 30, 2017).
3.11	Amendment No. 8 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated January 25, 2018 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on January 31, 2018).
3.12	Certificate of Formation of American Midstream GP, LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).

3.13	Fourth Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on August 15, 2017).
4.1	Indenture, dated as of December 28, 2016, among American Midstream Partners, LP, American Midstream Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on January 4, 2017).
4.2	Supplemental Indenture, dated as of March 8, 2017, among American Midstream Partners, LP, American Midstream Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 14, 2017).
4.3	Second Supplemental Indenture, dated as of September 18, 2017, among American Midstream Partners, LP, American Midstream Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on September 19, 2017).
4.4	Third Supplemental Indenture, dated as of December 19, 2017, among American Midstream Partners, LP, American Midstream Finance Corporation, the Guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on December 19, 2017).
4.5	Officers' Certificate of American Midstream Partners, LP and American Midstream Finance Corporation, as Issuers, dated December 19, 2017 (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on December 19, 2017).
4.6	Registration Rights Agreement, dated as of December 28, 2016, among the Partnership, the Co-Issuer, the Guarantors named therein and the Initial Purchasers named therein, relating to the Notes (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on January 4, 2017).
4.7	Registration Rights Agreement, dated as of December 19, 2017, among American Midstream Partners, LP, American Midstream Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein, relating to the Notes (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on December 19, 2017).
10.1	Second Amended and Restated Credit Agreement, dated as of March 8, 2017, 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 (Commission File No. 001-35257) filed on March 14, 2017).
10.2	Note Purchase and Guaranty Agreement 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 (Commission File No. 001-35257) filed on October 6, 2016).
10.3	Unit Purchase Agreement 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 (Commission File No. 001-35257) filed on November 4, 2016).
10.4	Unit Purchase Agreement 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 (Commission File No. 001-35257) filed on November 4, 2016).
10.5	Unit Purchase Agreement 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 (Commission File No.

	001-35257) filed on November 4, 2016).
10.6	Unit Purchase Agreement 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 (Commission File No. 001-35257) filed on November 4, 2016).
10.7	Unit Purchase Agreement 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 (Commission File No. 001-35257) filed on November 4, 2016).
10.8	Unit Purchase Agreement 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 (Commission File No. 001-35257) filed on November 4, 2016).
10.9	Securities Purchase Agreement 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 (Commission File No. 001-35257) filed on April 29, 2016).

10.10	Distribution Support and Expense Reimbursement Agreement 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 (Commission File No. 001-35257) filed on October 24, 2016).
10.11	Securities Purchase Agreement 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 (Commission File No. 001-35257) filed on November 4, 2016).
10.12	Amendment No. 1 to the Securities Purchase Agreement, dated as of October 31, 2016, between American Midstream Partners, LP and Magnolia Infrastructure Holdings, LLC, dated July 14, 2017 and effective as of June 30, 2017 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on July 14, 2017).
10.13	Amendment No. 2 to the Securities Purchase Agreement, dated as of October 31, 2016, between AMID and Magnolia Infrastructure Holdings, LLC, dated September 7, 2017 and effective as of August 31, 2017 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on September 11, 2017).
10.14	Membership Interest Purchase Agreement, dated July 21, 2017, between AMID Merger LP and SHV Energy N.V. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q (Commission File No. 001-35257) filed on November 9, 2017).
10.15	Distribution, Sale and Contribution Agreement, dated September 29, 2017, among D-Day Offshore Holdings, LLC, Toga Offshore, LLC, Pinto Offshore Holdings, LLC and American Midstream Delta House, LLC (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q (Commission File No. 001-35257) filed on November 9, 2017).
10.16+	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 (Commission File No. 333-216585) filed on March 9, 2017).
10.17+	Third Amended and Restated American Midstream GP, LLC Long-Term Incentive Plan (incorporated by reference to Exhibit A of the Definitive Proxy Statement on Schedule 14A (Commission File No. 001-35257) filed on January 11, 2016).
10.18+	Form of American Midstream Partners, LP Long-Term Incentive Plan Grant of Phantom Units (incorporated by reference to Exhibit 10.8 to the Registration Statement on Form S-1/A (Commission File No. 333-173191) filed June 9, 2011).
10.19+	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 the Registration Statement on Form S-1/A (Commission File No. 333-173191) filed June 9, 2011).
10.20+	Employment Agreement 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 (Commission File No. 001-35257) filed on December 14, 2015).
10.21+	Phantom Unit Award Agreement 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 (Commission File No. 001-35257) filed on December 14, 2015).
10.22+	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 (Commission File No. 001-35257) filed on November 8, 2016).
10.23+	Long-Term Incentive Plan Grant of Phantom Units between American Midstream GP, LLC and Eric T. Kalamaras, dated July 26, 2016 (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q (Commission File No. 001-35257) filed on November 8, 2016).
10.24+*	Form of American Midstream GP, LLC Long-Term Incentive Plan Grant of Phantom Units.
10.25+*	

	Form of Unit Purchase Option Grant Notice under the American Midstream GP, LLC Long-Term Incentive Plan.
21.1*	American Midstream Partners, LP, List of Subsidiaries.
23.1*	Consent of Independent Registered Public Accounting Firm-PricewaterhouseCoopers LLP.
23.2*	Consent of Independent Registered Public Accounting Firm-BDO USA, LLP.
23.3*	Consent of Independent Registered Public Accounting Firm-BDO USA, LLP.
23.4*	Consent of Independent Registered Public Accounting Firm-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*	2017 Pinto Offshore Holdings, LLC Financial Statements
99.2*	2017 Delta House FPS, LLC Financial Statements
99.3*	2017 Delta House Oil and Gas Lateral, LLC 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.
+Management contract or compensatory plan arrangement.
**Furnished 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

By: American Midstream GP, LLC, its General Partner

Date: April 9, 2018 By: /s/ Eric T. Kalamaras
Eric T. Kalamaras
Senior Vice President & Chief Financial Officer

(Principal Financial Officer)

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 below on April 9, 2018.

Signature	Title
/s/ Lynn L. Bourdon III Lynn L. Bourdon III	Chairman, 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 Board of Directors of American Midstream GP, LLC and to the Unitholders of American Midstream Partners, LP

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Midstream Partners, LP and its subsidiaries (the “Partnership”) as of December 31, 2017 and 2016, and the related consolidated statements of operations, of comprehensive loss, of changes in equity, partners’ capital and noncontrolling interests and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO because the following existed as of that date: (i) an ineffective control environment due to the lack of sufficient oversight of internal control over financial reporting and an insufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with the Partnership’s financial reporting requirements, which contributed to additional material weaknesses, as the Partnership did not (ii) design and maintain effective controls over the accounting for complex, non-routine transactions of the Partnership, (iii) design and maintain effective controls over revenue and receivables, (iv) design and maintain effective controls over acquisitions and divestitures, (v) design and maintain effective controls over the period end financial reporting process, (vi) design and maintain effective controls over asset retirement obligations, goodwill, other intangible, and finite-lived assets, and (vii) maintain effective controls over user access to ensure appropriate segregation of duties and that adequately restrict user and privileged access to a significant application, programs, and data to appropriate Partnership personnel.

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 weaknesses referred to above are described in Management’s Annual Report on Internal Control over Financial Reporting appearing under Item 9A. We considered these material weaknesses in determining the nature, timing, and extent of audit tests applied in our audit of the December 31, 2017 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.

Basis for Opinions

The Partnership's management is responsible for these consolidated 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 the Partnership’s consolidated financial statements and on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

As described in Management's Annual Report on Internal Control over Financial Reporting, management has excluded JP Energy Partners, LP ("JPE") from its assessment of the Partnership's internal control over financial reporting as of December 31, 2017 because it was acquired by the Partnership in a purchase business combination during 2017. We have also excluded JPE from our audit of the Partnership's internal control over financial reporting. JPE represents approximately 21.9% of consolidated assets and 51.4% of the consolidated revenues as of and for the year ended December 31, 2017.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (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
April 9, 2018

We have served as the Partnership's auditor since 2009.

American Midstream Partners, LP, and Subsidiaries
Consolidated Balance Sheets
(In thousands, except unit amounts)

	December 31, 2017	2016
Assets		
Current assets		
Cash and cash equivalents	$8,782	$5,666
Restricted cash	20,352	—
Accounts receivable, net of allowance for doubtful accounts of $225 and $630 as of December 31, 2017 and 2016, respectively	32,278	14,715
Unbilled revenue	65,854	52,910
Inventory	2,966	1,990
Other current assets	23,420	25,516
Current assets of discontinued operations	—	22,727
Total current assets	153,652	123,524
Property, plant and equipment, net	1,095,585	1,066,608
Restricted cash - long term	5,045	323,564
Investment in unconsolidated affiliates	348,434	291,987
Intangible assets, net	174,010	205,071
Goodwill	128,866	202,135
Other assets	17,874	22,400
Non-current assets of discontinued operations	—	114,032
Total assets	$1,923,466	$2,349,321
Liabilities, Equity and Partners' Capital		
Current liabilities		
Accounts payable	$41,102	$39,569
Accrued gas purchases	19,986	7,891
Accrued expenses and other current liabilities	68,854	72,721
Current portion of long-term debt	7,551	5,438
Current liabilities of discontinued operations	—	14,319
Total current liabilities	137,493	139,938
Asset retirement obligations	66,194	44,363
Other liabilities	2,080	1,858
3.77% Senior notes (non-recourse)	55,198	55,979
8.50% Senior notes	418,421	291,309
Revolving credit agreements	697,900	888,250
3.97% Trans-Union Secured Senior notes (non-recourse)	29,937	—
Deferred tax liability	8,123	8,205
Non-current liabilities of discontinued operations	—	172
Total liabilities	1,415,346	1,430,074
Commitments and contingencies (see Note 20)		
Convertible preferred units	317,180	334,090
Equity and partners' capital		
General Partner Interests (965 thousand and 680 thousand units issued and outstanding as of December 31, 2017 and 2016, respectively)	(96,552)	(47,645)
	273,703	616,087

Limited Partner Interests (52,711 thousand and 51,351 thousand units issued and outstanding as of December 31, 2017 and 2016, respectively)		
Accumulated other comprehensive income (loss)	28	(40)
Total partners' capital	177,179	568,402
Noncontrolling interests	13,761	16,755
Total equity and partners' capital	190,940	585,157
Total liabilities, equity and partners' capital	$1,923,466	$2,349,321

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

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American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Operations
(In thousands, except per unit amounts)

	Years Ended December 31,		
	2017	2016	2015
Revenues:			
Commodity sales	$496,902	$439,412	$613,241
Services	154,652	151,231	135,718
Gains (losses) on commodity derivatives, net	(119)	(1,617)	1,345
Total revenue	651,435	589,026	750,304
Operating expenses:			
Cost of sales	457,371	393,351	567,682
Direct operating expenses	82,256	71,544	71,729
Corporate expenses	112,058	89,438	65,327
Depreciation, amortization and accretion	103,448	90,882	81,335
(Gain) loss on sale of assets, net	(4,063)	688	2,860
Impairment of long-lived assets / intangible assets	116,609	697	—
Impairment of goodwill	77,961	2,654	148,488
Total operating expenses	945,640	649,254	937,421
Operating loss	(294,205)	(60,228)	(187,117)
Other income (expense):			
Interest expense	(66,465)	(21,433)	(20,077)
Other income	36,254	254	1,460
Earnings in unconsolidated affiliates	63,050	40,158	8,201
Loss from continuing operations before income taxes	(261,366)	(41,249)	(197,533)
Income tax expense	(1,235)	(2,580)	(1,885)
Loss from continuing operations	(262,601)	(43,829)	(199,418)
Income (loss) from discontinued operations, net of tax	44,095	(4,715)	(423)
Net loss	(218,506)	(48,544)	(199,841)
Net income (loss) attributable to noncontrolling interests	4,473	2,766	(13)
Net loss attributable to the Partnership	$(222,979)	$(51,310)	$(199,828)
General Partner's interest in net loss	$(2,981)	$(233)	$(1,823)
Limited Partners' interest in net loss	$(219,998)	$(51,077)	$(198,005)
Distribution declared per common unit	$1.65	$1.99	$2.14
Limited Partners' net income (loss) per common unit (See Note 17):			
Basic and diluted:			
Loss from continuing operations	$(5.70)	$(1.51)	$(4.91)
Income (loss) from discontinued operations	0.85	(0.09)	(0.01)
Net loss	$(4.85)	$(1.60)	$(4.92)
Weighted average number of common units outstanding:			
Basic and diluted	52,043	51,176	45,050

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

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American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Comprehensive Loss
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Net loss	$(218,506)	$(48,544)	$(199,841)
Unrealized gain (loss) relating to postretirement benefit plan	68	(80)	38
Comprehensive loss	$(218,438)	$(48,624)	$(199,803)
Less: Comprehensive income (loss) attributable to noncontrolling interests	4,473	2,766	(13)
Comprehensive loss attributable to Partnership	$(222,911)	$(51,390)	$(199,790)

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

American Midstream Partners, LP, and Subsidiaries
Consolidated Statements of Changes in Equity, 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	Total Equity and Partners' Capital
Balances at December 31, 2014	$55,490	$968,881	$32,220	$ 2	$1,056,593	$ 11,752	$1,068,345
Net loss	(1,823)	(198,005)	—	—	(199,828)	(13)	(199,841)
Issuance of common units, net of offering costs	—	85,465	—	—	85,465	—	85,465
Issuance of Series B Units	—	—	1,373	—	1,373		1,373
Unitholder contributions	1,996	—	—	—	1,996	—	1,996
Unitholder distributions	(7,023)	(111,740)	—	—	(118,763)	—	(118,763)
Distribution for acquisition of Delta House	(96,297)	—	—	—	(96,297)	—	(96,297)
Contributions from noncontrolling interest owners ("NCI")	—	—	—	—	—	739	739
Distributions to NCI owners	—	(20)	—	—	(20)	(367)	(387)
LTIP vesting	(2,490)	2,686	—	—	196	—	196
Tax netting repurchases	—	(756)	—	—	(756)	—	(756)
Equity compensation expense	3,056	1,309	—	—	4,365	—	4,365
Postretirement benefit plan	—	—	—	38	38	—	38
Contributions from general partner	—	5,568	—	—	5,568	—	5,568
Balances at December 31, 2015	$(47,091)	$753,388	$33,593	$ 40	$739,930	$ 12,111	$752,041
Net income (loss)	(233)	(51,077)	—	—	(51,310)	2,766	(48,544)
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—	(6,817)
Issuance of warrants	4,481	—	—	—	4,481	—	4,481
Issuance of common units, net of offering costs	—	2,697	—	—	2,697	—	2,697
Conversion of Series B Units	—	33,593	(33,593)	—	—	—	—
Unitholder contributions	1,998		—	—	1,998	—	1,998
Unitholder distributions	(7,938)	(130,761)	—	—	(138,699)	—	(138,699)
General Partner's contribution for acquisition	990	—	—	—	990	—	990
Contributions from NCI owners	—	—	—	—	—	3,366	3,366
Distributions to NCI owners	—	—	—	—	—	(1,488)	(1,488)
LTIP vesting	(3,486)	3,486	—	—	—	—	—
Tax netting repurchases	—	(346)	—	—	(346)	—	(346)
Equity compensation expense	3,634	2,024	—	—	5,658	—	5,658

Contributions from general partner	—	9,900	—	—	9,900	—	9,900
Postretirement benefit plan	—	—	—	(80)	(80)	—	(80)
Balances at December 31, 2016	$(47,645)	$616,087	$—	$ (40)	$568,402	$ 16,755	$585,157
Net income (loss)	(2,981)	(219,998)	—	—	(222,979)	4,473	(218,506)
Contributions from general partner	—	4,000	—	—	4,000	—	4,000
Unitholder contributions	46,317	—	—	—	46,317	—	46,317
Unitholder distributions	(1,370)	(122,849)	—	—	(124,219)	—	(124,219)
Distribution for acquisition of Delta House and Trans-Union	(86,335)	—	—	—	(86,335)	—	(86,335)
Common units issued for Panther acquisition	—	12,532	—	—	12,532	—	12,532
Contribution from GP for the Destin acquisition	278	—	—	—	278	—	278
Distribution for repurchase of Series D units	(2,555)	—	—	—	(2,555)	—	(2,555)
Acquisition of AMPAN NCI (Note 3)	(299)	(23,649)	—	—	(23,948)	(4,645)	(28,593)
Contributions from NCI owners	—	—	—	—	—	296	296
Distributions to NCI owners	—	—	—	—	—	(3,118)	(3,118)
LTIP vesting	(8,165)	8,165	—	—	—	—	—
Tax netting repurchases	—	(2,414)	—	—	(2,414)	—	(2,414)
Equity compensation expense	6,203	1,829	—	—	8,032	—	8,032
Postretirement benefit plan	—	—	—	68	68	—	68
Balances at December 31, 2017	$(96,552)	$273,703	$—	$ 28	$177,179	$ 13,761	$190,940

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,		
	2017	2016	2015
Cash flows from operating activities			
Net loss	$(218,506)	$(48,544)	$(199,841)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, amortization and accretion	113,271	107,029	100,877
Amortization of deferred financing costs	5,117	3,236	2,391
Amortization of weather derivative premium	1,030	966	912
Unrealized gain on derivative contracts, net	(1,109)	(11,400)	(11,269)
Non-cash compensation expense	8,032	5,658	4,365
Impairment of long-lived assets / intangible assets	116,609	697	4,970
Gain on MPOG acquisition (Note 3)	(35,999)	—	—
(Gains) losses on sale of assets and business (Note 4 and Note 11)	(51,497)	2,756	4,189
Impairment of goodwill	77,961	15,456	156,427
Other non-cash items	1,848	(486)	(463)
Earnings in unconsolidated affiliates	(63,050)	(40,158)	(8,201)
Distributions from unconsolidated affiliates	63,050	40,158	8,201
Deferred tax (benefit) expense	(82)	2,057	953
Bad debt expense	147	1,038	1,212
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:			
Accounts receivable	(10,346)	(5,430)	5,609
Inventory	(887)	(1,909)	13,095
Unbilled revenue	(11,990)	(219)	53,120
Risk management assets and liabilities	(596)	(1,030)	(875)
Other current assets	4,109	(795)	1,948
Other assets, net	—	682	(80)
Accounts payable	(5,949)	(2,242)	(50,885)
Accrued gas purchases	12,095	610	(7,045)
Accrued expenses and other current liabilities	8,425	15,384	3,623
Asset retirement obligations	(697)	(858)	(90)
Other liabilities	—	483	835
Corporate overhead support from General Partner	4,000	7,500	3,000
Net cash provided by operating activities	14,986	90,639	86,978
Cash flows from investing activities			
Acquisitions, net of cash acquired and settlements (Note 3)	(76,150)	(2,676)	(5,200)
Investments in unconsolidated affiliates (Note 11)	(81,517)	(150,179)	(65,703)
Additions to property, plant and equipment and other	(85,054)	(147,798)	(208,040)
Proceeds from sale of assets and business	168,917	11,788	8,730
Insurance proceeds from involuntary conversion of property, plant and equipment	150	—	—
Distributions from unconsolidated affiliates, return of capital	27,797	42,888	12,367
Restricted cash	298,167	(318,527)	7,075
Net cash provided by / (used in) investing activities	252,310	(564,504)	(250,771)

Cash flows from financing activities			
Proceeds from issuance of common units, net of offering costs	—	2,825	82,488
Contributions	46,317	1,998	1,905
Distributions (Notes 15 and 16)	(116,293)	(112,136)	(100,411)
Issuance of convertible preferred units, net of offering costs	—	34,413	44,768
Redemption of Series D preferred units (Note 15)	(34,475)	—	—
Unitholder distributions for common control transactions	(86,335)	—	(96,297)
Contributions from noncontrolling interest owners	296	3,366	584
Distributions to noncontrolling interest owners	(1,776)	(1,488)	(114)
LTIP tax netting unit repurchases	(2,414)	(521)	(1,045)
Payment of deferred financing costs	(5,172)	(5,327)	(2,244)
Proceeds from 3.77% Senior Notes	—	60,000	—
Payments of 3.77% Senior Notes	(1,677)	—	—
Proceeds from 8.50% Senior Notes	127,969	294,000	—
Proceeds from other debt	5,219	—	4,709
Payments of other debt	(5,160)	(3,136)	(4,069)
Other	(329)	—	(686)
Proceeds on revolving credit agreements	583,809	425,100	471,300
Payments of revolving credit agreements	(774,159)	(223,950)	(240,150)
Contributions from the predecessor	—	2,400	1,218
Net cash (used in)/ provided by financing activities	(264,180)	477,544	161,956
Net increase (decrease) in cash and cash equivalents	3,116	3,679	(1,837)
Cash and cash equivalents			
Beginning of period	5,666	1,987	3,824
End of period	$ 8,782	$ 5,666	$ 1,987

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

American Midstream Partners, LP, and Subsidiaries
Notes to Consolidated Financial Statements

1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Organization

General

American Midstream Partners, LP and subsidiaries (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 77% owned by High Point Infrastructure Partners, LLC ("HPIP") and 23% indirectly 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 five reportable segments, (1) gas gathering and processing services, (2) liquid pipelines and services, (3) natural gas transportation services, (4) offshore pipelines and services, and (5) terminalling services, 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 and refined products. Most of our cash flow is generated from fee-based and fixed-margin compensation for gathering, processing, transporting and treating natural gas and crude oil, firm capacity reservation charges, interruptible transportation charges, guaranteed firm storage contracts, throughput fees and other optional charges associated with ancillary services.

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 in key demand markets in Oklahoma, Alabama, Arkansas, Louisiana, Mississippi and Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia.

Basis of presentation

As discussed in Note 3- Acquisitions, we acquired JPE in a unit-for-unit exchange on March 8, 2017. As both the Partnership and JPE were controlled by ArcLight, the acquisition represents a transaction among entities under common control and has been accounted for as a common control transaction in a manner similar to a pooling of interests. Although the Partnership is the legal acquirer, JPE is considered to be the acquirer for accounting purposes as ArcLight obtained control of JPE before it obtained control the Partnership. The accompanying financial statements represent the JPE historical cost basis financial statements retrospectively adjusted to reflect its acquisition of the Partnership at ArcLight's historical cost basis effective April 15, 2013, the date on which ArcLight obtained control of the Partnership.

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's equity. As the transactions are between entities under common control we account for the net assets acquired at the affiliate's historical cost basis, whether the transactions are considered assets or business acquisitions. 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 affiliates obtained control of the assets or business 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.

Summary of Significant Accounting Policies

Use of estimates

When preparing consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("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.

Inventory

Inventory, which is mainly comprised of crude oil, refined products and NGLs, is stated at the lower of cost or net realizable value. Cost of crude oil, NGLs and refined products inventory is determined using the first-in, first-out (FIFO) method.

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. We recorded allowances for doubtful accounts of $0.2 million and $0.6 million, respectively, as of December 31, 2017 and 2016. Bad debt expense for the years ended December 31, 2017, 2016 and 2015 was approximately $0.1 million, $0.6 million and $0.0 million, respectively, which is excluding the impact of the sale of the Propane Business.

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 may use a variety of derivative financial instruments such as swaps, collars, interest rate caps or forward contracts to create offsetting positions to specific commodity or interest rate exposures. 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 our net income (loss) 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 related 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.

We are also a party to a number of contracts that have elements of a derivative instrument. These contracts are primarily forward crude oil purchase and sales contracts with counterparties. Although many of these contracts have the requisite elements of a derivative instrument, these contracts qualify for the normal purchase and normal sales exception because they provide for the delivery of products or services in quantities that are expected to be used in the normal course of operating our business and the price in the contract is based on an underlying that is directly associated with the price of the product or service being purchased or sold. As a result, these contracts are not recorded in our consolidated financial statements until they are settled.

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 impairment

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. Impairment of goodwill is the condition that exists when the carrying amount of goodwill exceeds its fair value and a goodwill impairment loss is recognized for the amount that the carrying amount exceeds its fair value. On an annual basis, or more frequently if needed, a qualitative review (Step Zero) is used to evaluate whether a condition for impairment exists. If it is the case, a quantitative impairment test (Step One) is then performed to identify goodwill impairment and measure the amount of impairment loss to be recognized, if any.

Intangible assets

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 five years and thirty 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. The unconsolidated affiliates that were determined to be variable interest entities (“VIE”) due to disproportionate economic interests and decision making rights were further evaluated under the VIE method of consolidation. In each case, we lack the power to direct the activities that most significantly impact the unconsolidated affiliate’s economic performance. Therefore, as we do not hold a controlling financial interest in these affiliates, we account for our related investments using the equity method. Additionally, our maximum exposure to loss related to each entity is limited to our equity investment as presented on the consolidated balance sheets as of the balance sheet date. In each case, we are not obligated to absorb losses greater than our proportional ownership percentages. Our right to receive residual returns is not limited to any amount less than the ownership percentages. We also have a joint venture arrangement in which we and our partners share proportional ownership and responsibilities and receive returns in accordance with our ownership percentage.

Deferred financing costs

Costs incurred in connection with our revolving credit facilities are deferred and charged to interest expense over the term of the related credit agreement. Such amounts are included in Other assets, net in our consolidated balance sheets. Costs incurred in connection with our long-term debt such as the 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 onshore 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. See Note 2 - Recent Accounting Pronouncements, for further discussion regarding our implementation of the new Revenue Recognition guidance beginning January 1, 2018.

Cost of sales

Cost of sales 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 plans, which provide 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 U.S. federal and state income taxes. We account for income taxes of that subsidiary using the asset and liability approach. 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.

2. New Accounting Pronouncements

Adopted in 2017

In January 2017, the FASB issued ASU No. 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business”. The guidance provides criteria for use in determining when to conclude an integrated “set of assets and activities (as defined in the original guidance) being acquired or disposed in a transaction" is not a business. Where the criteria are not met, more stringent screening has been provided to define a set as a business without an output, as more narrowly defined within the guidance. ASU No. 2017-01 is effective for annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments should be applied prospectively on or after the effective date. Early adoption is permitted. We elected to early adopt ASU No. 2017-01 on October 1, 2017.
In January 2017, the FASB issued ASU No. 2017-04, “Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment”, in which the guidance on testing for goodwill was updated by the elimination of Step 2 in the determination on whether goodwill should be considered impaired. The annual and/or interim assessments are still required to be completed. Further, the guidance eliminates the requirement to assess reporting units with zero or negative carrying values, however, the carrying values for all reporting units must be disclosed. ASU No. 2017-04 is effective for annual or any interim goodwill impairment tests beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We elected to early adopt the guidance in connection with our annual assessment performed in October 2017 using the required prospective method.

To Be Adopted in 2018 or Later

In May 2014, the FASB issued Accounting Standards Update (“ASU”) No. 2014-09, “Revenue from Contracts with Customers (Topic 606)”, with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. ASU No. 2014-09 supersedes the revenue recognition guidance in Topic 605, Revenue Recognition. The new standard establishes a single, principle-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. We have reviewed our various customer arrangements in order to determine the impact the new accounting guidance for revenue recognition will have on our consolidated financial statements and related disclosures. We also engaged a third-party consulting firm to assist us with all the three phases of adoption of the new guidance (Impact Assessment, Convert and Implement). We adopted the new standard on its effective date January 1, 2018 using the modified retrospective method of adoption.

Based on our assessment, the application of the new standard will result in the following changes to our consolidated financial statements and revenue recognition methods:

- Estimates of variable consideration which will be required under the new standard as well as the allocation of the transaction price for certain revenue contracts may result in changes to the pattern or timing of revenue recognition for those contracts,and

- Certain payments received from customers to offset the cost of constructing assets required to provide services to those customers, referred to as Contributions in Aid of Construction (CIAC) were previously recognized as incurred. Under the new standard, CIAC is deemed to be advance payments for services and must be recognized when those future services are provided. CIAC will be accounted for as deferred revenue and recognized over the term of the associated revenue contract.

Upon adoption as of January 1, 2018, we will recognize a cumulative effect of initially applying the new standard as a decrease in the opening balance of partners' capital of approximately $11 million.

In February 2016, the FASB issued ASU No. 2016-02 (Topic 842) "Leases", which supersedes the lease recognition requirements in ASC 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. We are in the process of evaluating the impact of ASU No. 2016-02 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 are engaging a third-party consulting firm to assist us with the adoption of the new guidance and are currently in the Impact Assessment phase. We are not yet able to determine whether the adoption of this standard will have a material impact on our consolidated financial statements and related disclosures, including additional changes, if any, to our accounting system to capture data for disclosures purpose. We will adopt the guidance on its effective date January 1, 2019.

In August 2016, the FASB issued ASU No. 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments", a consensus of the FASB's Emerging Issues Task Force. The new guidance which requires application using a retrospective transition method is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The ASU addresses how the following cash transactions are presented: (1) debt prepayment or debt extinguishment costs; (2) settlement of zero-coupon debt instruments; (3) contingent consideration payments made after a business combination; (4) proceeds from the settlement of insurance claims; (5) proceeds from the settlement of corporate-owned life insurance policies; (6) distributions received from equity method investments; (7) beneficial interests in securitization transactions and (8) cash receipts and cash payments that have aspects of multiple cash flow classifications. The impact of adopting the new guidance to our consolidated statements of cash flows using the retrospective transition method would be a) immaterial to Net cash provided by operating activities and Net cash provided by (used in) financing activities, and material to Net cash provided by (used in) investing activities for the year ended December 31, 2017, b) immaterial to Net cash provided by operating activities and Net cash provided by (used in) financing activities and material to Net cash provided by (used in) investing activities for the year ended December 31, 2016 and c) none for the year ended December 31, 2015. We adopted the standard upon its effective date January 1, 2018.

In November 2016, the FASB issued ASU No. 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 standard is effective beginning first quarter of 2018. Any adjustments required in adoption of this standard 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. As our restricted cash balances as of December 31, 2017 and 2016 were material, we have determined that the impact of this standard on our consolidated statements of cash flows and related disclosures would be material for such periods, considering the standard requires retrospective application. The impact of adopting the new guidance to our consolidated statements of cash flows using the retrospective transition method would be a) immaterial to Net cash provided by operating activities and Net cash provided by (used in) financing activities, and material to Net cash provided by (used in) investing activities for the years ended December 31, 2017 and 2016 and b) immaterial for the year ended December 31, 2015. We adopted the standard on its effective date of January 1, 2018.

In May 2017, the FASB issued ASU No. 2017-09, "Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting", to provide guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. Pursuant to this ASU, an entity should account for the effects of a modification unless all the following are met: (1) the fair value (or calculated value or intrinsic value, if such an alternative measurement method is used) of the modified award is the same as the fair value (or calculated value or intrinsic value, if such an alternative measurement method is used) of the original award immediately before the original award is modified (if the modification does not affect any of the inputs to the valuation technique that the entity uses to value the award, the entity is not required to estimate the value immediately before and after the modification); (2) the vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the original award is modified; and (3) the classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the original award is modified. ASU No. 2017-09 is effective for annual periods beginning after December 15, 2017, including interim periods within those periods. This update should be applied prospectively to an award modified on or after the adoption date. We adopted the guidance on its effective date January 1, 2018. Based on historical patterns of our granted unit-based awards, which did not involve material modifications, we do not believe that the impact of this update on our consolidated financial statements and related disclosures will be material.

In January 2018, the FASB issued ASU No. 2018-01 “Leases - Land Easement Practical Expedient for Transition to Topic 842”, to provide an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. An entity that does not elect this practical expedient should evaluate all existing or expired land easements in connection with the adoption of the new lease requirements in Topic 842 to assess whether they meet the definition of a lease. As discussed above, we are engaging a third-party consulting firm to assist us with the adoption of the new guidance and are currently in the Impact Assessment phase. We are not yet able to determine whether we would elect this practical expedient or whether the adoption of this standard will have a material impact on our consolidated financial statements and related disclosures, including additional changes, if any, to our accounting system to capture data for disclosures purpose. We will adopt this on its effective date January 1, 2019.

In March 2018, the FASB issued ASU No. 2018-05 “Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118 (SEC Update)”, to provide guidance for companies that have not completed their accounting for the income tax effects of the Tax Cuts and Jobs Act in the period of enactment. The measurement period begins in the reporting period that includes the Act’s enactment date December 22, 2017, and ends when a company has obtained, prepared and analyzed the information needed to complete the accounting requirements under ASC 740 and should not extend beyond one year from the enactment date. The impact of adopting the new guidance on our consolidated financial statements and related disclosures was immaterial.

3. Acquisitions

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, 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. 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 our Credit Agreement, as defined in Note 14 - Debt Obligations. As a result, we own a minority interest in Pinto, which represents an indirect interest in 12.9% of the Class A units of Delta House. Pursuant to the Pinto LLC Agreement, we have no management control or authority over the day-to-day operations.

Because our interest in Delta House was previously owned by an ArcLight affiliate, we recorded our investment at the affiliate's historical cost basis of $65.7 million in Investments in unconsolidated affiliates in our consolidated balance sheets and as an investing activity within the related consolidated statements of cash flows. The amount by which the total consideration exceeded the affiliate's historical cost basis was $96.3 million and is recorded as a distribution within the consolidated statements of changes in equity, partners’ capital and noncontrolling interests and as a financing activity in the consolidated statements 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 Class A units of Delta House in exchange for approximately $9.9 million in cash funded with borrowings under our 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 sheets and as an investing activity within our consolidated statements of cash flows.

On October 31, 2016, D-Day acquired an additional 6.2% direct interest in Class A units of Delta House 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 Units") to an ArcLight affiliate, plus $14.3 million in cash funded with borrowings under our Credit Agreement. Our share of Delta House earnings is reported in the Offshore Pipelines and Services segment gross margin.

On September 29, 2017, we acquired an additional 15.5% equity interest in Class A units of Delta House from affiliates of ArcLight for total cash consideration of approximately $125.4 million. As our 15.5% interest in Delta House was previously owned directly by ArcLight, we have accounted for our investment at our affiliate's carry-over basis resulting in $49.8 million recorded in Investments in unconsolidated affiliates in our consolidated balance sheets, and as an investing activity within the related consolidated statements of cash flows. The amount by which the total consideration exceeded the carry-over basis was $75.6 million and was recorded as a distribution to our general partner within the consolidated statements of changes in equity, partners' capital and noncontrolling interests and a financing activity in the consolidated statements of cash flows.

As of December 31, 2017, the Partnership and ArcLight indirectly own a 35.7% and 23.3% interest, respectively, in Delta House. Such 35.7% interest, includes a 35.7% interest in Delta House FPS LLC ("FPS"), which entitles us to receive 100% of the distributions from FPS until a certain payout threshold is met. Once the payout threshold is met, approximately 7% of the distributions from FPS will be paid to the Class B membership interests in FPS.

For the year ended December 31, 2017, the Partnership recorded $41.3 million in equity earnings from Delta House. The Partnership also received cash distributions of $43.7 million during the year. The excess of the cash distributions received over the earnings recorded from Delta House is classified as a return of capital within cash flows from investing activities in our consolidated statements of cash flows.

Our interest in Pinto is accounted for as an equity method investment in the consolidated financial statements.

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 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").

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, in exchange for a cash purchase price of approximately $27.4 million (such transaction, 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 and upon the consent of the holders of the Series C Units. Our share of earnings of the entities underlying the Emerald Transactions is included in the Liquid Pipelines and Services segment gross margin.

Because our interests in the entities underlying the Emerald Transactions were previously owned by an ArcLight affiliate, we recorded our investments at the affiliate's historical cost basis of $212.0 million , in Investment in unconsolidated affiliates in our consolidated balance sheets, and as an investing activity of $100.9 million within the consolidated statements 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 statements of changes in equity, partners' capital and noncontrolling interests.

On October 27, 2017, American Midstream Emerald, LLC, a wholly-owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement with Emerald Midstream, LLC, an ArcLight affiliate, to purchase an additional 17.0% equity interest in Destin for total consideration of $30.0 million. As our 17% interest in Destin was previously owned directly by ArcLight, we have accounted for our investment at our affiliate's carry-over basis resulting in $30.3 million recorded in Investments in unconsolidated affiliates in our consolidated balance sheets, and $30.0 million as an investing activity within the related consolidated statement of cash flows. The amount by which the total consideration was below the carry-over basis was $0.3 million and was recorded as a contribution from our general partner within the consolidated statement of changes in equity, partners' capital and noncontrolling interests and a non-cash financing activity in Note 22 - Supplemental Cash flow information for the year ended December 31, 2017. With the acquisition, the Partnership now owns a 66.7% interest in Destin.

As Destin continues to be a variable interest entity ("VIE"), the Partnership applied the guidance in ASC 810 - Consolidation to determine if either member has a controlling financial interest and if the Partnership is the primary beneficiary. As a result of our analysis, neither party has a controlling financial interest nor is the Partnership the primary beneficiary, and so the Partnership should not consolidate Destin. As it is not appropriate for the Partnership to consolidate Destin under the VIE model, we revisited the analysis in ASC 323 Investments-Equity Method and Joint Ventures, to determine the appropriate accounting for our interests and concluded that the Partnership should continue to account for Destin using the equity method of accounting as it continues to have the ability to exert significant influence over Destin's operations.

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 Offshore Pipelines and Services 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 statement of operations for 2016.

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.

Southern Propane Inc.

On May 8, 2015, we acquired substantially all of the assets of Southern Propane Inc. (“Southern”), a Houston-based industrial and commercial propane distribution and logistics company. The acquisition expanded the asset base and market share of our Propane Marketing Services segment, specifically the acceleration of our entry into the Houston, Texas market, as well as expansion of our industrial, non-seasonal customers. The total purchase price of $16.3 million consisted of a $12.5 million cash payment that was paid on the acquisition date, and which was funded through the use of borrowings under our Credit Agreement, a $0.1 million cash payment to the seller as the final working capital adjustment, the issuance of 266,951 common units valued at $3.4 million and a contingent earn-out liability with an acquisition date fair value of $0.3 million. The gross profit targets were not achieved and the remaining $0.2 million liability was released to income in 2016.

The $16.3 million purchase price was allocated to customer relationship intangible assets of $6.2 million , goodwill of $5.8 million, property, plant and equipment of $3.0 million, accounts receivable of $1.0 million and other intangible assets of $0.3 million. Goodwill associated with the acquisition principally results from synergies expected from integrated operations. The fair values of the acquired intangible assets were estimated by applying the income approach which is based on significant inputs that are not observable in the market and represents a Level 3 measurement. The customer relationship assets are being amortized over a weighted average useful life of 12 years. The Southern acquisition is part of the Propane Business that was sold in September 2017, see Note 4 - Discontinued Operations, for additional information regarding the sale of the Propane Business.

JP Energy Partners LP

On March 8, 2017, the Partnership completed the acquisition of JPE, an entity controlled by ArcLight affiliates, in a unit-for-unit exchange. 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 represented a transaction among entities under common control. Although the Partnership was the legal acquirer, JPE was considered the acquirer for accounting purposes as ArcLight obtained control of JPE on April 15, 2013 before it obtained control of the Partnership. In addition, the accompanying consolidated financial statements and related notes of past periods have been retrospectively adjusted to include the historical results of JPE prior to the effective date of the JPE Merger. The accompanying consolidated financial statements and related notes present the combined financial position, results of operations, cash flows and equity of JPE at historical cost.

Viosca Knoll Gathering System

On June 2, 2017, we acquired 100% of VKGS from Genesis Energy, L.P. for total consideration of approximately $32.0 million in cash and have accounted for this acquisition as a business combination. VKGS serves producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico and connects to several major delivery pipelines including the Partnership's High Point and Destin pipelines. VKGS will provide greater East-West Gulf connectivity, through the connection of the High Point Gas Transmission system and the Destin Pipeline, both operated by us. The VKGS acquisition was funded with the borrowings under our Credit Agreement, and VKGS was added to our Offshore Pipelines and Services segment.

The following table presents our aggregated allocation of the purchase price based on fair values of assets and liabilities acquired at the date of acquisition, June 2, 2017 (in thousands):

	Purchase Price Allocation
Property, plant and equipment:	
Pipelines and right-of-way	$ 13,433
Equipment	18,853
Total property, plant and equipment	32,286
Liability	(286)
Total cash consideration	$ 32,000

The pro forma effect of our business acquisition of VKGS was immaterial to our consolidated statements of operations for the year ended December 31, 2017 and the comparative periods, respectively, and therefore has not been separately disclosed.

Panther

On August 8, 2017, the Partnership acquired 100% of the interest in POGS, PPL and POC from Panther for approximately $60.9 million. The consideration included $39.1 million cash, funded from borrowings under the Partnership's Credit Agreement, and common units representing limited partner interests in the Partnership, valued at $12.5 million based on unit value as of the acquisition date. Panther owns and operates more than 1,000 miles of oil and gas pipelines, primarily in Texas and Louisiana offshore state and federal waters. The underlying acquired assets are highly complementary to the Partnership's core Gulf of Mexico assets as a substantial portion of Panther's cash flows are generated by our joint ventures.

As part of the purchase of POGS, we acquired the outstanding interests in one of our equity investments, MPOG, as well as the remaining equity interest in our consolidated subsidiary, AmPan. As such, the Partnership now owns 100% of MPOG and AmPan. We determined that the acquisition of the remaining interest in MPOG on August

8, 2017 resulted in a change in control and MPOG has been consolidated from the acquisition date. The effect was the Partnership's previously held equity interest in MPOG was remeasured to fair value and the excess (approximately $36.0 million) of fair value over historical carrying value was recognized as a gain in Other income on the consolidated statement of operations for the year ended December 31, 2017.

For AmPan, which has historically been consolidated by the Partnership, the acquisition of Panther's remaining interest resulted in the acquisition of a noncontrolling interest. Accordingly, the excess of the fair value of the acquired interest of $28.6 million over the carrying value of the noncontrolling interest (approximately $4.6 million) has been reported as a reduction to general partner and limited partner interests. PPL owns a 50% undivided ownership interest in the Matagorda and the Brazoria County Gas systems which will be proportionally consolidated from the acquisition date. POC operates pipeline assets on behalf of both third parties and affiliates of the Partnership for a fee and will be fully consolidated by the Partnership.

The following table presents the aggregated allocation of the purchase price based on estimated fair values of Panther's assets acquired and liabilities assumed at the date of acquisition, August 8, 2017 (in thousands):

	Purchase Price Allocation
Fair value of acquired noncontrolling interest	$ 28,597
Property, plant and equipment	19,497
Intangibles (customer relationships)	5,984
Net working capital, net of cash acquired	2,095
Goodwill	4,692
Total	$ 60,865

As of December 31, 2017, we updated our purchase price allocations with all available information.

The pro forma effect of our business acquisition of Panther entities was immaterial to our consolidated statements of operations for the year ended December 31, 2017 and the comparative periods, and therefore has not been separately disclosed.

Acquisition of Trans-Union pipeline
On November 3, 2017, we completed the acquisition of 100% of the equity interests in Trans-Union Interstate Pipeline, LP ("Trans-Union") from affiliates of ArcLight, for a total consideration of approximately $49.4 million. The consideration consisted of approximately $16.9 million in cash funded from borrowings under our Credit Agreement and the assumption of the remaining balance of $32.5 million non-recourse debt with 3.97% interest, quarterly payments and maturity date on December 31, 2032. See Note 14 - Debt Obligations for more information. Trans-Union owns a 42-mile, 30-inch diameter high-pressure FERC-regulated natural gas interstate pipeline with 546,000 MMbtu/day of maximum capacity. As a result, the results of these operations will be reported in our Natural Gas Transportation Services segment. See Note 23 - Reportable Segments. As the transaction represents an asset acquisition among entities under common control, as defined by ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business", we did not have to recast our historical financial statements to reflect the accounts of Trans-Union from the date ArcLight obtained control. Instead, we recorded the acquired assets at carry over basis or ArcLight's historical cost.

4. Discontinued Operations

Propane Business

On September 1, 2017, the Partnership completed the disposition of the Propane Business pursuant to the Membership Interest Purchase Agreement dated July 21, 2017, between AMID Merger LP, a wholly owned subsidiary of the Partnership, and SHV Energy N.V. Through the transaction, we divested Pinnacle Propane's 40 service locations; Pinnacle Propane Express' cylinder exchange business and related logistic assets; and the Alliant Gas utility system. Prior to the sale, we moved the trucking business from the Propane Business segment to the Liquid Pipelines and Services segment. With the disposition of the Propane Business, we eliminated the Propane Marketing Services segment.

In connection with the transaction, the Partnership received approximately $170.0 million in cash, net of customary closing adjustments. We recorded a gain of $47.4 million, net of $2.5 million of transaction costs, which is included in (Gains) losses on sale of assets and business line item on the Partnership's consolidated statement of cash flows for the year ended December 31, 2017. The Partnership has reported the accounts and the results of our Propane Business as discontinued operations in our consolidated statements of operations.

The following tables summarize the financial information related to the Propane Business for the corresponding years.

Consolidated Statement of Operations

	Year Ended December 31,		
	2017 [1]	2016	2015
	(in thousands)		
Total revenues [1]	$87,520	$137,896	$163,583
Costs and Expenses			
Costs of sales [1]	38,961	49,672	62,621
Direct operating expenses	35,177	51,828	55,751
Corporate expenses	7,174	9,992	12,508
Impairment of goodwill	—	12,802	—
Depreciation, amortization and accretion	9,823	15,936	17,261
(Gain) loss on sale of assets, net	(55)	2,182	1,060
Total expenses	91,080	142,412	149,201
Operating (loss) income	(3,560)	(4,516)	14,382
Other Income (expense)			
Interest expense	(36)	(36)	(43)
Other income	316	374	272
(Loss) income from discontinued operations before income tax expense	(3,280)	(4,178)	14,611
Income tax benefit (expense)	(59)	2	(3)
Net income (loss) from discontinued operations	(3,339)	(4,176)	14,608
Partnership's gain from the sale of discontinued operations [1]	47,434	—	—
Partnership's income (loss) from discontinued operations, including gain on sale	$44,095	$(4,176)	$14,608

[1] Includes a) adjustments resulting from recently available information such as a derivative adjustment of $0.1 million in Total revenues and an expense adjustment of $1.1 million in Cost of sales and b) a purchase price close adjustment of $0.9 million during the fourth quarter. The Partnership's gain from the sale of discontinued operations is reported in (Gains) losses on sales of assets and business line item on the consolidated statement of cash flows for the year ended December 31, 2017.

Consolidated Balance Sheet

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	Year Ended December 31, 2016 (in thousands)
ASSETS	
Current assets	
Accounts receivable, net	$ 13,055
Unbilled revenue	2,736
Inventory	4,785
Other current assets	2,151
Total current assets of discontinued operations	22,727
Non-current assets	
Property, plant and equipment, net	78,395
Goodwill	15,361
Intangible assets, net	20,212
Risk management assets	37
Other assets, net	27
Total non-current assets of discontinued operations	114,032
Total assets	$ 136,759
LIABILITIES	
Current liabilities	
Accounts payable	$ 5,709
Accrued expenses and other current liabilities	8,563
Current portion of long-term debt	47
Total current liabilities of discontinued operations	14,319
Non-current liabilities	
Other liabilities	172
Total non-current liabilities of discontinued operations	172
Total liabilities	$ 14,491

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The following table summarizes other selected financial information related to the Propane Business:

	Year ended December 31,		
	2017	2016	2015
	(in thousands)		
Depreciation	$8,074	$13,108	$14,455
Amortization	1,749	2,828	2,806
Capital expenditures	3,143	6,549	17,503
Other operating non-cash items			
Impairment of goodwill	—	12,802	—
(Gain) loss on sale of assets	(55)	2,182	1,060
Unrealized (gain) loss on derivative contracts, net	—	(1,072)	(11,764)

Mid-Continent

On February 1, 2016, we sold certain trucking and marketing assets in the Mid-Continent area (the “Mid-Continent Business”) to JP Development for $9.7 million in cash. We recognized a loss on the disposal of approximately $12.9 million during the year ended December 31, 2015, which primarily related to goodwill and long-lived asset impairment charges. Prior to the classification as discontinued operations, we reported the Mid-Continent Business in our Liquid Pipelines and Services segment.

Financial information for the Mid-Continent Business which is included in Loss from discontinued operations, net of tax in the consolidated statement of operations is summarized below:

	Year Ended December 31,	
	2016	2015
Revenues		
Total revenues	$11,495	$429,784
Costs and Expenses		
Costs of sales	11,687	426,886
Direct operating expenses	203	2,269
Loss on impairment of goodwill and assets held for sale	—	12,909
Depreciation, amortization and accretion	211	2,281
(Gain) loss on sale of assets, net	(114)	119
Total expenses	11,987	444,464
Operating loss	(492)	(14,680)
Other expense	(47)	(271)
Loss from discontinued operations before income tax expense	(539)	(14,951)
Income tax expense	—	—
Net loss from discontinued operations	$(539)	$(14,951)

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The following table is a reconciliation of the line item Income (loss) from discontinued operations on the consolidated statements of operations to the individual discontinued operations for the years presented:

	Year Ended December 31,		
	2017	2016	2015
Discontinued operations:			
(Loss) income from propane operations	$(3,339)	$(4,176)	$14,608
Gain on the sale of Propane Business	47,434	—	—
Mid-Continent discontinued operations	—	(539)	(14,951)
Blackwater discontinued operations	—	—	(80)
Total income (loss) from discontinued operations	$44,095	$(4,715)	$(423)

5. Concentration of Credit Risk

Significant customers are defined as those who represent 10% of more of our consolidated revenue during the year. In 2017, we had two such customers which accounted for 23% and 13%, respectively, of our consolidated revenue, Occidental Petroleum Corporation ("Occidental") and Royal Dutch Shell. The revenue from Occidental is reported in our Liquid Pipelines and Services and Terminalling Services segments. The revenue from Shell is reported in our Gas Gathering and Processing Services, Liquid Pipelines and Services, Offshore Pipelines and Services and Terminalling Services segments.

In 2016, we had two customers which accounted for 21% and 13%, respectively, of our consolidated revenue, Occidental and Plains All American Pipeline, L.P. In 2015, we had one such customer, Occidental, which accounted for 34% of our consolidated revenue.

We are party to various commercial netting agreements that allow us and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

6. Inventory

Inventory consists of the following:

	December 31,	
	2017	2016
	(in thousands)	
Crude oil	$1,553	$1,216
NGLs	347	288
Refined products	934	—
Materials, supplies and equipment	132	486
Total inventory	$2,966	$1,990

7. Other Current Assets

Other current assets consist of the following:

	December 31,	
	2017	2016
	(in thousands)	
Prepaid expenses	$8,944	$9,702
Insurance receivables	1,741	1,624
Other receivables	5,187	2,997
Due from related parties	4,362	4,833
Risk management assets	3,186	469
Other assets	—	5,891
Total other current assets	$23,420	$25,516

8. 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 to some extent in commodity price increases. Management regularly monitors the commodity markets and our 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.

To meet this objective, we use a combination of fixed price swaps, basis swaps and forward contracts. 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. At times, we may also terminate or unwind hedges or portions of hedges in order to meet cash flow objectives or when the expected future volumes do not support the level of hedges. Our forward contracts that qualify for the normal purchase normal sale exception are recognized when the underlying physical transaction is delivered. While these contracts are considered derivative financial instruments, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction no longer meets the exception, the fair value of the related contract is recorded on the consolidated balance sheets and immediately recognized through earnings.

The following table summarizes the net notional volume buy (sell) of our outstanding commodity-related derivatives, excluding those derivatives that qualified for the normal purchase normal sale exception as of December 31, 2017 and 2016, none of which were designated as hedges for accounting purposes.

	December 31, 2017		December 31, 2016	
	Notional Volume	Maturity	Notional Volume	Maturity
Commodity Swaps:				
Crude Oil Basis (Barrels)	—	—	180,000	Jan 2017 - Mar 2017

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, 2017 and 2016, we had a combined notional principal amount of $550.0 million and $650.0 million, respectively, of variable to fixed interest rate swap agreements. As of December 31, 2017, the maximum length of time over which we have hedged a portion of our exposure due to interest rate risk was through December 31, 2022.

The fair value of our interest rate swaps was estimated using a valuation methodology based upon forward interest rates 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 2017 and 2016, 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 $1.1 million and $1.0 million in 2017 and 2016, 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 $0.5 million and $0.4 million at December 31, 2017 and December 31, 2016, respectively, and are included in Other current assets on the consolidated balance sheets.

The following table summarizes the fair value of our derivative contracts (before netting adjustments) included in the consolidated balance sheets (in thousands):

		Asset Derivatives		Liability Derivatives	
		December 31		December 31	
Type	Balance Sheet Classification	2017	2016	2017	2016
Commodity swaps	Other current assets	$—	$ 112	$ —	$ —
Commodity swaps	Accrued expenses and other current liabilities	—	—	—	(1)
Commodity swaps	Other liabilities	—	—	—	(1)
Interest rate swaps	Other current assets	$2,678	$ —	$ —	$ —
Interest rate swaps	Accrued expenses and other current liabilities	—	—	—	(252)
Interest rate swaps	Other assets, net	8,807	10,628	—	—
Weather derivative	Other current assets	$509	$ 429	$ —	$ —

The following tables present the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset in the consolidated balance sheets that are subject to enforceable master netting arrangements (in thousands):

Balance Sheet Classification	Gross Risk Management Position December 31, 2017	December 31, 2016	Netting Adjustment December 31, 2017	December 31, 2016	Net Risk Management Position December 31, 2017	December 31, 2016
	(in thousands)					
Other current assets	$3,187	$ 541	$ —	$ (72)	$3,187	$ 469
Other assets, net	8,807	10,628	—	(1)	8,807	10,627
Total assets	$11,994	$ 11,169	$ —	$ (73)	$11,994	$ 11,096
Accrued expenses and other current liabilities	$—	$ (253)	$ —	$ 72	$—	$ (181)
Other liabilities	—	(1)	—	1	—	—
Total liabilities	$—	$ (254)	$ —	$ 73	$—	$ (181)

For the years ended December 31, 2017, 2016 and 2015, 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 following captions:

	Realized	Unrealized
	(in thousands)	
2017		
Losses on commodity derivatives, net	$(119)	$—
Interest expense	89	1,109
Direct operating expenses	(1,030)	—
Total	$(1,060)	$1,109
2016		
Losses on commodity derivatives, net	$(1,569)	$(48)
Interest expense	(144)	10,375
Direct operating expenses	(966)	—
Total	$(2,679)	$10,327
2015		
Gains (losses) on commodity derivatives, net	$1,632	$(287)
Interest expense	(425)	373
Direct operating expenses	(913)	—
Total	$294	$86

9. Property, Plant and Equipment, Net

Property, plant and equipment, net, consists of the following:

	Useful Life (in years)	December 31, 2017	December 31, 2016
		(in thousands)	
Land	N/A	$ 18,145	$ 18,861
Construction in progress	N/A	55,622	128,519
Transportation equipment	5 to 15	22,697	20,010
Buildings and improvements	4 to 40	16,235	13,762
Processing and treating plants	8 to 40	123,138	120,977
Pipelines and compressors	3 to 40	974,301	804,815
Storage	3 to 40	146,105	146,408
Equipment	5 to 20	80,220	77,978
Total property, plant and equipment		1,436,463	1,331,330
Less accumulated depreciation		(340,878)	(264,722)
Property, plant and equipment, net		$ 1,095,585	$ 1,066,608

At December 31, 2017 and 2016, gross property, plant and equipment included $367.6 million and $291.1 million, respectively, related to our FERC regulated interstate and intrastate assets.

Depreciation expense totaled $76.9 million, $69.7 million and $60.6 million for the years ended December 31, 2017, 2016 and 2015, respectively, which is included in Depreciation, amortization and accretion expense in the consolidated statements of operations. Depreciation expense amounts have been adjusted by $8.1 million, $13.2 million, and $15.5 million for the years ended December 31, 2017, 2016 and 2015, respectively, to present the impact of classifying the Propane Business and Mid-Continent's operations as discontinued operations, with the Propane Business being divested in September 2017 and Mid-Continent's operations being divested in February 2016. Capitalized interest was $2.5 million, $2.7 million and $1.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Impairment

During the fourth quarter of 2017, we identified certain assets where events or circumstances indicated we may not recover their carrying value. Due to plant shut downs in the quarter and changes in our forecast volumes on certain assets as part of our annual budget process, we made decisions that impact our ability to recover the carrying value of assets. Accordingly, we have impaired our Yellow Rose, Bazor Chatom, Burns Point and Transtar assets in our Gas Gathering and Processing Services segment, COSL in our Liquid Pipeline and Services segment and Trigas in our Natural Gas Transportation services segment. The total impairment charge was $103.9 million related to our property, plant and equipment. The impairment consisted of $97.8 million related to our Gas Gathering and Processing Services segment, $3.9 million related to our Natural Gas Transportation Services segment and $2.2 million related to our Liquid Pipelines and Services segment. Our fair value measurements related to these assets are based on significant inputs not observable in the market and thus represent a Level 3 measurement.

There were no impairments in 2015 and an impairment of $0.7 million was recorded in 2016.

10. Goodwill and Intangible Assets, Net

Goodwill

Overview

Under the Step Zero approach, we look to qualitative factors to determine if it is “more-likely-than not” the fair value of the reporting unit is less than its carrying value. If based upon the qualitative review, we determine that it is more-likely-than not that the fair value is in excess of its carrying value, then there is no requirement to perform additional steps. If we determine it is "more-likely than not" the fair value is less than the carrying value, we move to Step One, where we compare the fair value of a reporting unit to its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill associated with the reporting unit ("RU") is not considered impaired, and no further review is required. If the fair value of the RU is less than the carrying amount, the goodwill impairment is calculated as the difference between the RU's fair value and carrying amount, not to exceed the carrying amount of the goodwill. The fair value is estimated using the income approach based on significant inputs not observable in the market and thus represent a Level 3 measurement.

2015 Impairment

In 2015, as a result of our Step One analysis in the fourth quarter, we determined that the estimated fair value of certain reporting units within our Gas Gathering and Processing Services reportable segment and Liquid Pipelines and Services reportable segment were less than their respective carrying amounts, primarily due to changes in assumptions related to commodity prices, the 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 at the time. Step Two 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 Gas Gathering and Processing Services reportable segment and we recognized an impairment charge of $118.6 million which consisted of $95.0 million and $23.6 million related to the Costar and Lavaca systems, respectively. In addition, we recognized a $29.9 million impairment charge in our Liquid Pipelines and Services reportable segment relating to our COSL business and JP Liquids. As a result, we recognized total goodwill impairment charges of $148.5 million during the year ended December 31, 2015.

2016 Impairment

In the fourth quarter of 2016, we recognized additional goodwill impairment charges totaling $2.7 million related to our JP Liquids businesses reported in our Liquid Pipelines and Services reportable segment as a result of our Step Two goodwill impairment analysis. We also recorded a goodwill impairment charge of $12.8 million in 2016 related to our Pinnacle Propane Express business that we disposed, which is reported in Net loss from discontinued operations in the 2016 consolidated statement of operations.

2017 Impairment

In 2017, as a result of our annual Step One analysis in the fourth quarter, we identified that the fair value of our Silver Dollar and COSL reporting units, which are both in our Liquid Pipelines and Services segment, exceeded their carrying values. Accordingly, we recorded an impairment charge of $78.0 million, of which $61.4 million is related to Silver Dollar and $16.6 million is related to COSL.

The following table presents activity in the Partnership's goodwill balance as of December 31, 2017 and 2016:

	Offshore Pipelines and Services	Liquid Pipelines and Services	Terminalling Services	Total
	(in thousands)			
Balance at January 1, 2016	$—	$116,323	$ 88,466	$204,789
Impairment charges	—	(2,654)	—	(2,654)
Balance at December 31, 2016	—	113,669	88,466	202,135
Addition[(1)]	4,692	—	—	4,692
Impairment charges	—	(77,961)	—	(77,961)

Balance at December 31, 2017	$4,692	$35,708	$ 88,466	$128,866

(1) In 2017, due to our Panther acquisition discussed in Note 3 - Acquisitions, our goodwill balance increased by approximately $4.7 million associated with the Panther assets acquired and reported in our Offshore Pipelines and Services segment.

Intangible assets, net

Overview

Intangible assets, net, consists of customer relationships, customer contracts, dedicated acreage agreements, and collaborative arrangements as acquired in connection with business combinations. These intangible assets have definite lives and are subject to amortization on a straight-line basis over their economic lives, currently ranging from approximately 5 years to 30 years.

Intangible assets, net, consist of the following:

	December 31,					
	2017	2016	2017	2016	2017	2016
	Gross carrying amount		Accumulated amortization		Net carrying amount	
	(in thousands)					
Customer relationships	$110,483	$106,417	$(29,965)	$(23,245)	$80,518	$83,172
Customer contracts	94,692	94,692	(48,173)	(33,228)	46,519	61,464
Dedicated acreage	42,547	53,350	(6,216)	(4,439)	36,331	48,911
Collaborative arrangements	11,884	11,884	(1,415)	(601)	10,469	11,283
Noncompete agreements	1,064	1,063	(1,064)	(1,000)	—	63
Other	198	198	(25)	(20)	173	178
	$260,868	$267,604	$(86,858)	$(62,533)	$174,010	$205,071

In 2015, prior to the sale of the Mid-Continent Business on February 1, 2016, we recorded an intangible asset impairment charge of $0.7 million related to customer relationships, which was included in Income (loss) from discontinued operations line item in the consolidated statement of operations of such year.

During the fourth quarter of 2017, we identified certain assets where events or circumstances indicated we may not recover their carrying value. Accordingly, we recorded impairment charges of $10.8 million associated with the dedicated acreage related to our Yellow Rose asset in our Gas Gathering and Processing segment and $1.9 million associated with customer relationships related to our COSL asset in our Liquid Pipelines and Services segment. The charges are reported as a component of Impairment of long-lived assets / intangible assets line item in the consolidated statement of operations for the year ended December 31, 2017. Our fair value measurements related to these assets are based on significant inputs not observable in the market and thus represent a Level 3 measurement.

For the years ended December 31, 2017, 2016 and 2015, amortization expense on our intangible assets was $24.3 million, $19.2 million and $20.0 million, respectively, which is included depreciation, amortization and accretion in the consolidated statements of operations. Amortization expense of $1.7 million, $2.9 million and $4.0 million for the years ended December 31, 2017, 2016 and 2015, respectively, relates to the sale of the Propane Business in 2017, Mid-Continent Business and Propane Business in 2016 and Mid-Continent Business and Propane Business in 2015, respectively, and is included in Net loss from discontinued operations, net of tax line item in the consolidated statement of operations.

Estimated amortization expense for each of the next five years ranges from $13.3 million to $14.9 million, with an aggregate $118.6 million to be recognized in subsequent years.

The storage tank capacity in our crude oil storage facility in Cushing, Oklahoma is dedicated to one customer pursuant to a long-term contract with an initial expiration date of August 3, 2017 and an optional two-year renewal term. We did not receive a notice of the customer's intent to renew this contract by the required date of February 3, 2017 and therefore we have accelerated the remaining amortization of the related customer relationship intangible of approximately $9.9 million over the remaining term of the contract, which expired on August 3, 2017.

11. Investment in Unconsolidated Affiliates

For additional information about acquisitions by the Partnership of investments in unconsolidated affiliates, see Note 3 - Acquisitions.

Joint Venture with Targa Midstream Services, LLC

On August 8, 2017, we entered into a new joint venture agreement with Targa Midstream Services, LLC ("Targa") by which our previously wholly owned subsidiary Cayenne Pipeline, LLC ("Cayenne") became the Cayenne joint venture between Targa and us ("Cayenne JV"). We received $5.0 million in cash in exchange for the sale of 50% ownership interest in Cayenne to Targa. The sole asset of the joint venture is a natural gas pipeline which was converted into a NGL pipeline. Both parties will each have 50% economic interests and 50% voting rights, with Targa serving as the operator of the pipeline and the joint venture. The additional costs of conversion and associated construction are shared equally by us and Targa. On December 28, 2017, the pipeline became operational. The gain recognized associated with this joint venture is included in the (Gains) losses on sales of assets and business line item on the consolidated statement of cash flows for the year ended December 31, 2017.

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[2]	Cayenne JV	Total
	(in thousands)								
Ownership % at December 31, 2016	20.1 %	20.1 %	49.7 %	16.7 %	66.7 %	25.3 %	66.7 %	—	
Ownership % at December 31, 2017	35.7 %	35.7 %	66.7 %	16.7 %	66.7 %	25.3 %	— %	50.0 %	
Balance at December 31, 2014	$—	$—	$—	$—	$—	$—	$10,368	$—	$10,368
Investments	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
Investments	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	—	—	—	—	—	—	429	—	429
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	4,147	—	291,987
Investments	22,538	27,289	30,240	—	—	—	(2,365)	—	77,702
Earnings (losses) in unconsolidated affiliates	28,794	12,536	9,457	4,395	7,719	719	(682)	112	63,050
Contributions	—	—	—	—	—	—		6,542	6,542
Distributions	(25,403)	(18,343)	(26,334)	(6,360)	(12,333)	(974)	(1,100)	—	(90,847)

Balance at December 31, 2017	$90,412	$46,932	$124,245	$53,057	$22,445	$4,689	$—	$6,654	$348,434

(1) Represents direct and indirect ownership interests in Class A units.
(2) We purchased the remaining equity interest in MPOG on August 8, 2017. See Note 3 - Acquisitions.

The following tables include summarized data for the entities underlying our equity method investments:

	December 31,	
	2017(1)	2016
	(in thousands)	
Current assets	$80,405	$120,167
Non-current assets	1,288,862	1,369,492
Current liabilities	130,904	133,085
Non-current liabilities	436,584	541,312

	Years ended December 31,		
	2017[1]	2016	2015
	(in thousands)		
Revenue	$364,398	$370,263	$235,041
Operating expenses	29,900	99,084	90,453
Net income	258,897	261,200	135,083

12. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consists of the following (in thousands):

	December 31,	
	2017	2016
Capital expenditures	$10,721	$14,274
Accrued interest	3,190	5,743
Convertible preferred unit distributions	—	7,103
Employee compensation	90	8,438
Current portion of asset retirement obligation	6,416	6,499
Additional Blackwater acquisition consideration	5,000	5,000
Transaction costs	3,408	3,000
Customer deposits	1,109	148
Taxes payable	5,263	1,186
Due to related parties	6,609	4,072
Deferred financing costs	266	2,743
Professional fees	1,848	638
Contingent liabilities associated with VKGS and Panther	2,099	—
Royalties, gas imbalance and leases payables	7,905	6,068
Accrued corporate expenses	2,487	2,665
Accrued operating expenses	6,609	—
Other	5,834	5,144
Total accrued expenses and other current liabilities	$68,854	$72,721

13. Asset Retirement Obligations

Overview

On a annual basis, we review our ARO liabilities. There are certain cases when 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 such 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.

The following table presents activity in the Partnership's asset retirement obligations (in thousands):

	Years Ended December 31, 2017	2016
Beginning balance	$50,862	$35,371
Liabilities assumed [1]	8,922	14,542
Revaluation of estimates [2]	11,516	230
Expenditures	(697)	(858)
Accretion expense	2,007	1,577
Ending balance	72,610	50,862
Less: current portion	6,416	6,499
Noncurrent asset retirement obligation	$66,194	$44,363

[1] Includes $14.3 million assumed in connection with the Gulf of Mexico Pipeline acquisition in 2016 and $8.7 million assumed in connection with the Panther acquisition on August 8, 2017 described in Note 3 - Acquisitions. This assumed ARO in 2017 was associated with PPL, POGS and MPOG entities. Of the balance, the total ARO associated with MPOG was approximately $7.0 million. This balance represents 100% of the ARO balance associated with MPOG that we assumed as a result of purchasing the remaining 33.3% of ownership of MPOG, which was our 66.7% investment pre-August 8, 2017.

[2] Represents updated liability associated with the ARO relating to our High Point assets in the Offshore Pipelines and Services segment. This update was due to our annual review of ARO obligations which resulted in a revised estimated cost of the original ARO recorded.

We may be required to establish security against potential ARO 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, long-term in our consolidated balance sheets as of December 31, 2017 and 2016.

14. Debt Obligations

Our outstanding debt consists of the following as of December 31, 2017:

	AMID Revolving Credit Agreement [1]	Trans-Union 3.97% Senior Notes due 2032	AMID 8.50% Senior Notes due due 2021	AMID 3.77% Senior Notes due due 2031	AMID Other Debt	Total
	(in thousands)					
Balance	$697,900	32,025	$425,000	$58,324	$4,989	$1,218,238
Less unamortized deferred financing costs and discount	—	(333)	(6,579)	(2,319)	—	(9,231)
Subtotal	697,900	31,692	418,421	56,005	4,989	1,209,007
Less current portion	—	(1,755)	—	(807)	(4,989)	(7,551)
Non-current portion	$697,900	29,937	$418,421	$55,198	$—	$1,201,456

[1] Unamortized deferred financing costs related to the Credit Agreement are included in Other assets, net.

Our outstanding debt consists of the following as of December 31, 2016:

	AMID Revolving Credit Agreement [1]	JPE Revolving Credit Agreement [1]	AMID 8.50% Senior Notes due 2021	AMID 3.77% Senior Notes due 2031	AMID Other Debt	Total
	(in thousands)					
Balance	$711,250	$177,000	$300,000	$60,000	$3,762	$1,252,012
Less unamortized deferred financing costs and discount	—	—	(8,691)	(2,345)	—	(11,036)
Subtotal	711,250	177,000	291,309	57,655	3,762	1,240,976
Less current portion	—	—	—	(1,676)	(3,762)	(5,438)
Non-current portion	$711,250	$177,000	$291,309	$55,979	$—	$1,235,538

[1] Unamortized deferred financing costs related to the Credit Agreement are included in Other assets, net.

AMID Revolving Credit Agreement

On March 8, 2017, the Partnership along with other subsidiaries of the Partnership (collectively, the “Borrowers”) entered into the 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 or Credit Agreement, which increased the Borrowers’ borrowing capacity thereunder from $750.0 million to $900.0 million and provided for an accordion feature that will permit, subject to 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 Credit Agreement includes a $30 million sublimit for borrowings by Blackwater Investments, Inc. and a $100 million sublimit for letters of credit. The Credit Agreement matures on September 5, 2019. All obligations under the Credit Agreement and the guarantees of those obligations are secured, subject to certain exceptions, by a first-priority lien on and security interest in (i) substantially all of the Borrowers’ assets and the assets of certain of the subsidiaries of the Partnership and (ii) the capital stock of certain of the Partnership’s subsidiaries.

We can elect to have loans under our Credit Agreement bear interest either at (a) a Eurodollar-based rate, plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or (b) 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," and (iii) a Eurodollar-based rate plus 1.00%, in each case of clause (i)-(iii), 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 from 0.375% to 0.50% per annum, depending on our total leverage ratio then in effect, on the undrawn portion of the revolving loan under the Credit Agreement.

The guarantees by the Guarantors 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.

The Credit Agreement contains certain financial covenants that are applicable as of the end of any fiscal quarter, including a consolidated total leverage ratio which requires our indebtedness not to exceed 5.00 times adjusted consolidated EBITDA (provided that the minimum consolidated total leverage may be increased to 5.50 times adjusted consolidated EBITDA in connection with the closing of certain material acquisitions as of the end of the quarter during which such acquisition closes, and as of the end of the subsequent two quarters), a consolidated secured leverage ratio which requires our secured indebtedness not to exceed 3.50 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. Regarding the total leverage ratio, in the first three quarters of 2017, we were in compliance with the covenants requirements ratios of 5.50 times, 5.50 times and 5.00 times, for quarter periods ended March 31, 2017, June 30, 2017 and September 30, 2017, respectively, as described above. During the fourth quarter of 2017, we elected to be in a Specified Acquisition Period, as defined in Section 7.19 Financial Covenants of the Credit Agreement, which enables us to use a ratio of 5.50 times for the fourth quarter of 2017 as well as the first and second quarters of 2018.

As of December 31, 2017, our consolidated total leverage ratio was 5.23, our consolidated secured leverage ratio was 3.29, and our interest coverage ratio was 3.62, which were all in compliance with the related covenants of our Credit Agreement. At December 31, 2017 and 2016, letters of credit outstanding under the Credit Agreement were $24.1 million and $7.4 million, respectively. As of December 31, 2017, we had approximately $697.9 million of borrowings outstanding.

The carrying value of amounts outstanding under the Credit Agreement approximates the related fair value, as interest charges vary with market rates conditions. For the years ended December 31, 2017, 2016 and 2015, the weighted average interest rate on borrowings under our Credit Agreement was approximately 4.96%, 4.29%, and 3.67%, respectively.

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 terms of the Credit Agreement also include covenants that restrict our ability to make cash distributions and acquisitions in some circumstances. If required, ArcLight , which controls the General Partner of the Partnership, has confirmed its intent to provide financial support for the Partnership to maintain compliance with the covenants contained in the Credit Agreement through April 10, 2019.

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

JPE Credit Agreement

On February 12, 2014, we entered into the JPE Credit Agreement with Bank of America, N.A, which was available for refinancing and repayment of certain existing indebtedness, working capital, capital expenditures, permitted acquisitions and other general partnership purposes. The JPE Credit Agreement consisted of a $275.0 million revolving loan, which included a sub-limit of up to $100.0 million for letters of credit.

Borrowings under the JPE Credit Agreement bore interest at a rate per annum equal to, at our option, either (a) a base rate determined by reference to the highest of (1) the federal funds effective rate plus 0.5%, (2) the prime rate of Bank of America, and (3) LIBOR, subject to certain adjustments, plus 1.00% or (b) LIBOR, in each case plus an applicable rate. The applicable rate was (a) 1.25% for prime rate borrowing and 2.25% for LIBOR borrowings. The commitment fee was subject to an adjustment each quarter based in the Consolidated Net Total Leverage Ratio, as defined in the related agreement. The carrying value of amounts outstanding under the JPE Credit Agreement approximates the related fair value, as interest charges vary with market rate conditions.

The JPE Credit Agreement was scheduled to mature on February 12, 2019, but was paid off and terminated on March 8, 2017 in connection with the Partnership's acquisition of JPE.

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 $300 million aggregate principal amount of their 8.50% Senior Notes due 2021 (the "8.50% Senior Notes"). The 8.50% Senior Notes are jointly and severally guaranteed by certain of the Partnership's subsidiaries. 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. 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 the JPE Credit Facility and to reduce borrowings under the Partnership’s

Credit Agreement.

On December 19, 2017, the Issuers completed the issuance and sale of an additional $125 million in aggregate principal amount of 8.50% Senior Notes (the “Additional Issuance”), net of issuance cost of approximately $3.0 million.

The Additional Issuance will mature on December 15, 2021 and interest on the Additional Issuance will accrue from December 15, 2017. Interest on the Additional Issuance is payable in cash semiannually in arrears on each June 15 and December 15, with interest payable on the Additional Issuance commencing June 15, 2018. Interest will be payable to holders of record on the June 1 and December 1 immediately preceding the related interest payment date, and will be computed on the basis of a 360-day year consisting of twelve 30-day months. Pursuant to the registration rights agreements entered into in connection with the issuances of the 8.50% Senior Notes, additional interest on the 8.50% Senior Notes accrues at 0.25% per annum for the first 90-day period following December 23, 2017 and by an additional 0.25% per annum with respect to each subsequent 90-day period, up to a maximum additional rate of 1.00% per annum over 8.50%, until we complete an exchange offer for the 8.50% Senior Notes.

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.

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 because the Senior Notes were issued on December 28, 2016. The carrying value of the 8.50% Senior Notes as of December 31, 2017 approximates the fair value as of that date of $437.1 million. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

3.77% Senior Notes

On September 30, 2016, Midla Financing, LLC ("Midla Financing"), American Midstream (Midla), LLC (“Midla”), and 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 proceeds of approximately $57.7 million, net of debt 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, 2017, Restricted cash includes $14.9 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, 2017 and 2016, the fair value of the 3.77% Senior Notes was $53.8 million and $54.6 million, respectively. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

3.97% Trans-Union Secured Senior Notes

On May 10, 2016, Trans-Union Interstate Pipeline, LP ("Trans-Union") entered into an agreement with certain institutional investors in the insurance business represented by Babson Capital Management LLC whereby Trans-Union issued $35.0 million in aggregate principal amount of 3.97% Senior Secured Notes ("Trans-Union Senior Notes") due December 31, 2032. Principal and interest on the Trans-Union Senior Notes is payable in installments on the last business day of each quarter beginning June 30, 2016 with the remaining balance payable in full on December 31, 2032. The average quarterly principal payment is approximately $0.5 million. The Trans-Union Senior Notes were issued at par and provided a net proceeds of approximately $34.6 million after deducting related issuance cost of approximately $0.4 million. The Partnership assumed the Trans-Union Senior Notes following the Trans-Union acquisition on November 3, 2017. See Note 3 - Acquisitions. As of December 31, 2017, the fair value of the 3.97% Senior Notes was approximately $30.2 million. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

15. Convertible Preferred Units

Our convertible preferred units consist of the following:

	Series A		Series C		Series D		Total
	Units	$	Units	$	Units	$	$
	(in thousands)						
December 31, 2015	9,210	$169,712	—	$—	—	$—	$169,712
Issuance of units	—	—	8,571	115,457	2,333	34,475	149,932
Paid in kind unit distributions	897	11,674	221	2,772	—	—	14,446
December 31, 2016	10,107	$181,386	8,792	$118,229	2,333	$34,475	$334,090
Repurchase of units	—	—	—	—	(2,333)	(34,475)	(34,475)
Paid in kind unit distributions	612	10,412	173	7,153	—	—	17,565
December 31, 2017	10,719	$191,798	8,965	$125,382	—	$—	$317,180

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 C Units may be made in cash, paid-in-kind units or a combination thereof, at the election of the Board of Directors of our General Partner and upon the consent of the holders of the Series C Units. 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 $0.4125 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, 2017, the conversion price was $15.23.

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 $15.23 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. The sale of the Series A-1 Units was exempt from registration under Securities Act pursuant to Rule 4(a)(2) under the Securities Act.

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 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, 2017, the conversion price was $15.23. The sale of the Series A-2 Units was exempt from registration under Securities Act pursuant to Rule 4(a)(2) under the Securities Act.

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-2 Units have been classified as mezzanine equity in the consolidated balance sheets.

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 3- Acquisitions.

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, 2017, the conversion price was $13.39.

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 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.

In connection with the issuance of the Series C Units, the Partnership issued to the holders (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 was 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. As a result of such adjustment, the number of common units that can be purchased upon the exercise of the Series C Warrant increased by 416,485 common units.

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. As of December 31, 2017, the number of common units that can be purchased upon the exercise of the Series C Warrant increased to 1,253,260 common 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.

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 C Units have been classified as mezzanine equity in the consolidated balance sheets.

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 3 - Acquisitions. The fair value of the conditional Series D Warrant at the time of issuance was immaterial.

On October 2, 2017, pursuant to the terms of our Partnership Agreement, we exercised our call right to repurchase all of the 2,333,333 outstanding Series D Units from Magnolia for approximately $37.0 million in cash, which was funded through our Credit Agreement. Of this amount, approximately $2.5 million was associated with the dividend distribution associated with Series D Units, as reported in line item Distributions on our consolidated statements of cash flows. After the closing date of such redemption, which occurred on October 2, 2017, there were no more outstanding Series D Units.

16. Partners' Capital

American Midstream Outstanding Units

The following table presents unit activity (in thousands):

	General Partner Interest	Limited Partner Interest	Series B Convertible Units
Balances at December 31, 2014	392	42,640	1,255
Issuance of Series B Units	—	—	95
LTIP vesting	—	58	—
Issuance of GP units	144	—	—
Exercise of unit options	—	152	—
Issuance of common units	—	7,654	—
Balances at December 31, 2015	536	50,504	1,350
Conversion of Series B Units	—	1,350	(1,350)
LTIP vesting	—	283	—
Return of escrow units	—	(1,034)	—
Issuance of GP units	144	—	—
Issuance of common units	—	248	—
Balances at December 31, 2016	680	51,351	—
LTIP vesting	—	431	—
Issuance of GP units	285	—	—
Issuance of common units	—	929	—
Balances at December 31, 2017	965	52,711	—

Our capital accounts are comprised of approximately 1.3% notional General Partner interest and 98.7% limited partner interests as of December 31, 2017. 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 is 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 3 - Acquisitions. 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 year ended December 31, 2015, the Partnership issued 94,923 of paid-in-kind Series B Units with a fair value of $1.4 million.

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 $100.0 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. There were no offerings under the ATM program in 2017.

In September 2015, the Partnership sold 7.5 million 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 3. 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.

General Partner Units

In order to maintain its ownership percentage, we received proceeds of $4.0 million from our General Partner as consideration for the issuance of additional notional 284,886 general partner units for the year ended December 31, 2017, 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, 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,		
	2017	2016	2015
Series A Units			
Cash:			
Paid	$8,354	$4,935	$—
Accrued	—	2,514	—
Paid-in-kind units [1]	10,412	11,674	16,978
Total	18,766	19,123	16,978
Series B Units			
Paid-in-kind units	—	—	1,373
Total	—	—	1,373
Series C Units			
Cash:			
Paid	12,186	3,089	—
Accrued	—	3,626	—
Paid-in-kind units [2]	7,153	2,772	—
Total	19,339	9,487	—
Series D Units			
Cash:			
Paid	2,887	—	—
Accrued	—	963	—
Total	2,887	963	—
Limited Partner Units			
Cash:			
Paid	89,378	101,561	93,622
Accrued	—	—	—
Total	89,378	101,561	93,622
General Partner Units			
Cash:			
Paid	3,488	2,551	6,789
Accrued	—	—	—
Additional Blackwater acquisition consideration	—	5,000	—
Total	3,488	7,551	6,789
Summary			
Cash			
Paid	116,293	112,136	100,411
Accrued	—	7,103	—
Paid-in-kind units	17,565	14,446	18,351
Additional Blackwater acquisition consideration	—	5,000	—
Total	$133,858	$138,685	$118,762

[1] Includes accruals for $3.8 million, $2.7 million and $4.4 million as of December 31, 2017, 2016 and 2015, respectively.
[2] Includes accruals for $4.3 million and zero as of December 31, 2017 and 2016, respectively.

On January 26, 2018, 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 14, 2018, to unitholders of record as of the close of business on February 7, 2018. Accrued cash distributions on our preferred convertible units were also paid in February 2018.

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 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 $3.86 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%.

Our Partnership Agreement provides that the General Partner may, in its sole discretion, make cash distributions, but there is no requirement that we make any cash distributions.

17. 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 ("IDRs"). 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 loss per common unit is summarized below (in thousands, except per unit amounts):

	Years Ended December 31,		
	2017	2016	2015
Loss from continuing operations	$(262,601)	$(43,829)	$(199,418)
Less: Net income (loss) attributable to noncontrolling interests	4,473	2,766	(13)
Loss attributable to the Partnership	(267,074)	(46,595)	(199,405)
Less:			
Distributions on Series A Units	16,237	19,138	16,978
Distributions on Series C Units	15,712	9,487	—
Distributions on Series D Units	1,925	963	—
Distributions on Series B Units	—	—	1,373
General partner's distributions	1,053	2,550	6,790
General partner's share in undistributed loss	(5,108)	(1,691)	(3,498)
Loss attributable to Limited Partners	(296,893)	(77,042)	(221,048)
Income (loss) from discontinued operations, net of tax	44,095	(4,715)	(423)
Net loss attributable to Limited Partners	$(252,798)	$(81,757)	$(221,471)
Weighted average number of common units outstanding - basic and diluted	52,043	51,176	45,050
Limited Partners' net income (loss) per common unit - Basic and Diluted			
Loss from continuing operations	$(5.70)	$(1.51)	$(4.91)
Income (loss) from discontinued operations	0.85	(0.09)	(0.01)
Net loss	$(4.85)	$(1.60)	$(4.92)

[(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 loss per common unit.

18. Incentive Compensation

Overview

Our General Partner manages our operations and activities and employs the personnel who provide support to our operation. Unit-based awards, which are available on a limited basis, or other types of incentive compensation such as our Defined Contribution Plan, which is available to all employees, are designed to retain, motivate and reward talented employees and key management personnel.

Unit-Based Compensation Plans

All equity-based awards issued under the Long-Term Incentive Plan consist of phantom units, distribution equivalent rights ("DER"), option grants or performance-based awards. DERs, options and performance-based awards 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.

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 in effect as of the date hereof, the "LTIP").

After March 8, 2017, pursuant to the JPE Merger, we assumed the JP Energy Partnership 2014 Long-Term Incentive Plan, which was renamed the American Midstream Partners, LP Amended and Restated 2014 Long Term Incentive Plan (the “Assumed LTIP”). As of December 31, 2017, there were 151,845 Common Units available for awards under the Assumed LTIP, as adjusted to reflect the JPE Merger. We settle the existing awards made under the Assumed LTIP with the Common Units reserved under the Assumed LTIP. See JPE Unit-Based Compensation below for detailed information.

At December 31, 2017, 2016 and 2015, there were 4,134,412, 5,017,528 and 15,484 common units, respectively, available for future grants under the LTIP.

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, 2017, 2016 and 2015 (in thousand, except per unit data):

	Units[2]	Weighted-Average Grant Date Fair Value Per Unit	Aggregate Intrinsic Value [1]
Outstanding units 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 units 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 units at December 2016	1,245,843	$ 4.72	$ 22,674
LTIP associated with the acquired JPE phantom units[2]	312,992	15.73	
Outstanding units at January 1, 2017	1,558,835	$ 6.98	
Granted	586,173	10.66	
Forfeited	(136,053)	10.52	
Vested	(600,977)	11.38	
Outstanding units at December 2017[2]	1,407,978	$ 6.29	$ 18,797

[1] The intrinsic value of phantom units was calculated by multiplying the closing market price of our underlying units on December 31, 2017, 2016, 2015 and 2014 by the number of phantom units.

[2] Including 10,344 of phantom units which remain outstanding from the Assumed LTIP.

The fair value of our phantom units, which are subject to equity classification, is derived from the fair value of our common units at the grant date. Fair value of phantom units is calculated based on either a) the market price of underlying units on the date of grant, less the estimated life time (vesting period)'s dividend distribution, if the phantom units have a restricted feature associated with the distribution or b) the market price of underlying units on the date of grant.

Compensation expense related to these phantom unit based awards for the years ended December 31, 2017, 2016, and 2015 was $7.9 million, $3.6 million and $3.8 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 equity, partners' capital and noncontrolling interests.

The total fair value of units at the time of vesting was $9.8 million, $2.4 million, and $2.6 million for the years ended December 31, 2017, 2016, and 2015, respectively.

Equity compensation expense related to unvested phantom awards not yet recognized at December 31, 2017 was $6.0 million and the weighted average period over which this expense is expected to be recognized as of December 31, 2017 is approximately 1.43 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, 2017 and 2016 was $0.2 million and $0.9 million, respectively, and is included in Direct operating expenses in our consolidated statements of operations. The remaining unrecognized compensation expense related to unvested awards as of December 31, 2017 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 completely 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 options to an executive to purchase 45,000 common units of the Partnership at an exercise price per unit equal to $13.88. The options were to vest at a rate of 25% per year and to expire on September 30th of the calendar year following the calendar year in which they completely vest. Such options have been forfeited during 2017.

In April 2017, the Board of Directors of our General Partner approved the grant of options to purchase 15,000 common units of the Partnership at an exercise price per unit equal to $14.85. The options will vest over four years at a rate of 25% per year. The options will expire on April 30th of the calendar year following the calendar year in which they completely vest.

The Black-Scholes pricing model was used to determine the fair value of our option grants using the following assumptions:

	Years Ended December 31,	
	2017	2016
Weighted average common unit price volatility	65.0%	61.1%
Expected distribution yield	11.1%	12.6%
Weighted average expected term (in years)	3.79	4.1
Weighted average risk-free rate	1.63%	1.1 %

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 with a term equivalent to the vesting period.

Compensation expense related to these option awards was not material for the years ended December 31, 2017, 2016 and 2015. Compensation cost related to unvested option awards not yet recognized at December 31, 2017 was $0.1 million.

The following table summarizes our option activity for the years ended December 31, 2017 and 2016:

	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, 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
Granted	15,000	14.85	3.69	—	—
Vested	—	—	—	—	—
Forfeited	(45,000)	13.88	2.74	—	—
Outstanding at December 31, 2017	245,000	$ 8.09	$ 0.80	$ 1,211	3.1

(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 (strike price) of the option.

Performance Based Awards. In November 2017, the Board of Directors of our General Partner approved the grant of 524,000 performance based awards ("PSUs") to create a highly accretive, long-term retention tool to key personnel whom management expects to drive performance over the long-term. The awards will vest on November 20, 2022, subject to acceleration in certain circumstances.

A Monte-Carlo pricing model was used to determine the fair value of our grants using the following assumptions:

	December 31, 2017
Weighted average common unit price volatility (historical)	60.0 %
Expected distribution yield	13.15 %
Weighted average expected term (in years)	1 year to 5 years
Weighted average risk-free rate	1.6% to 2.1%

The compensation expense related to these PSU awards for the year ended December 31, 2017 was $0.1 million. Compensation expense related to the unvested PSU awards not yet recognized was $6.2 million as of December 31, 2017.

JPE Unit-Based Compensation

Long-Term Incentive Plan and Phantom Units. The JPE 2014 Long-Term Incentive Plan (or "Assumed LTIP" following the JPE Merger) authorized grants of up to 3,642,700 common units. Phantom units issued under the Assumed LTIP were primarily composed of two types of grants: (1) service condition grants with vesting over three years in equal annual installments; and (2) service condition grants with cliff vesting on April 1, 2018. Distributions related to these unvested phantom units are paid concurrent with our distribution for common units. The fair value of phantom units issued under the Assumed LTIP was determined by utilizing the market value of our common units on the respective grant date.

The following table presents phantom units activity for the years ended December 31, 2015 to 2016:

	Units	Weighted Average Grant date Fair Value
Outstanding units at December 31, 2014	—	$ —
Granted	287,750	22.25
Vested	(4,766)	22.34
Forfeited	(56,005)	21.23
Outstanding units at December 31, 2015	226,979	$ 22.50
Granted	209,507	9.23
Vested	(55,778)	19.51
Forfeited	(67,716)	18.74
Outstanding units at December 31, 2016 [1]	312,992	$ 14.96

[1] Post-acquisition date March 8, 2017 of JPE by the Partnership, as discussed in Note 3 - Acquisitions, the Assumed LTIP was adopted by the Partnership, as discussed above. All the 312,992 shares under Assumed LTIP have become part of the LTIP program, as disclosed in Phantom Unit Awards above.

As a result of the JPE Merger, certain JPE unit-based awards have been modified for JPE employees who stayed for the transition period. Such awards with a vest date of April 1, 2018 have been modified over the requisite service period to their respective target completion dates of April 8, 2017, May 31, 2017, July 14, 2017 or September 8, 2017. The incremental fair value of
the modified awards which was recorded prospectively within 2017 was based on the conversion ratio (of JPE phantom units to the Partnership's units) multiplied by the Partnership's unit price on the date immediately preceding the acquisition date of March 8, 2017 of $16.45. The total fair value of JPE modified awards was approximately $1.5 million and was expensed in the year ended December 31, 2017.

Total unit-based compensation expense related to the Assumed LTIP was $1.7 million and $0.8 million for the years ended December 31, 2016 and 2015, respectively, which was recorded in Corporate expenses in the consolidated statements of operations. The unit-based compensation expense related to the Assumed LTIP for the year ended December 31, 2017 was included in the total phantom unit-based compensation for the year ended December 31, 2017, as discussed in Phantom Unit Awards above, as a result of the JPE Merger.

Defined Contribution Plan

We have an employee savings plan (the "401(k) Plan") under Section 401(k) of the Internal Revenue Code of 1986, as amended, whereby employees of our General Partner may contribute a portion of their base compensation to the employee savings plan, subject to limits. We provide a matching contribution each payroll period equal to 100% of the employee's contribution up to the lesser of 6% of the employee's eligible compensation or $16,200 annually for the period. The matching contribution vests immediately upon eligibility, which is defined as first day of employment. As a result of the JPE Merger, the 401(k) Plan of JPE is included in our financial statements for the periods presented.

The following table summarizes information regarding contributions and the expense recognized for the matching contributions, which is included in operating and maintenance expense and general and administrative expense in our statements of operations (in thousands):

	For the year ended December 31,		
	2017	2016	2015
Matching contributions expensed for the 401(k) Plan	$2,047	$1,964	$2,358

19. Income Taxes

With the exception of certain subsidiaries in our Terminalling Services 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, 2017, 2016 and 2015 is as follows:

	Years Ended December 31,		
	2017	2016	2015
Current income tax expense	$1,317	$523	$648
Deferred income tax expense (benefit)	(82)	2,057	1,237
Total income tax expense	1,235	2,580	1,885
Effective income tax rate	(0.5)%	(6.3)%	(1.0)%

A reconciliation of our expected income tax expense calculated at the U.S. federal statutory rate of 34% to our actual tax expense for the years ended December 31, 2017, 2016 and 2015 is as follows:

	Years Ended December 31,		
	2017	2016	2015
Loss from continuing operations before income taxes	$(261,366)	$(41,249)	$(197,533)
US Federal statutory tax rate	34 %	34 %	34 %
Federal income tax benefit at statutory rate	(88,864)	(14,025)	(67,161)
Reconciling items:			
Partnership loss not subject to income tax benefit	89,711	15,800	68,048
State and local tax expense	2,664	800	857
Rate change	(2,369)	—	—
Other	93	5	141
Income tax expense	$1,235	$2,580	$1,885

The Partnership’s deferred tax assets and liabilities as of December 31, 2017 and 2016 are summarized below:

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	December 31, 2017	December 31, 2016
Deferred tax assets:		
Net operating loss carryforwards	$6,646	$6,300
Other	86	577
Total deferred tax assets	6,732	6,877
Deferred tax liabilities:		
Property, plant and equipment	14,855	15,082
Deferred income tax liability, net	$(8,123)	$(8,205)

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act of 2017 ("Tax Reform Act"). Among a number of significant changes to the current U.S. federal income tax rules, the Tax Reform Act reduces the marginal U.S. corporate income tax rate from 34 percent to 21 percent, limits the current deduction for net interest expense, limits the use of net operating losses to offset future taxable income, and provides for full expense deduction for certain business capital expenditures for 2018 and subsequent years. The tax rates used in calculating deferred income taxes reflect the enacted tax law.

As of December 31, 2017, certain subsidiaries in our Terminalling Services segment had net operating loss carryforwards for federal income tax purposes of approximately $26.0 million which begin to expire in 2029.

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, 2017, 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 2011 remain subject to examination by federal and state taxing authorities.

20. Commitments and Contingencies

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 proceedings 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.

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 statements of operations.

As part of the JPE Merger on March 8, 2017, management of JPE communicated to its employees a severance plan. The plan includes termination benefits in the form of severance and accelerated vesting of phantom units for employees who rendered service through their respective termination date. The remaining liability associated with these termination benefits were immaterial as of December 31, 2017.

Commitments

The Partnership had the following non-cancelable contractual commitments as of December 31, 2017 (in thousands):

Commitments	Total	2018	2019	2020	2021	2022	Thereafter
3.77% Senior Notes	$58,324	$807	$2,233	$2,299	$4,430	$4,579	$43,976
8.50% Senior Notes[1]	425,000	—	—	—	425,000	—	—
3.97% Secured Senior Notes	32,025	1,755	1,805	1,852	1,900	1,952	22,761
Revolving Credit Agreements	697,900	—	697,900	—	—	—	—
Capital Lease Obligations	95	95	—	—	—	—	—
Operating Lease Obligations[4]	33,759	5,263	4,878	3,385	2,906	2,058	15,269
Asset Retirement Obligation[2]	72,610	6,416	—	—	—	—	66,194
Other[3]	129,948	6,853	2,317	2,356	2,361	2,401	113,660
Total	$1,449,661	$21,189	$709,133	$9,892	$436,597	$10,990	$261,860

(1) Upon closing of the JPE Merger, the proceeds from the 8.50% Senior Notes were used to repay the JPE Credit Agreement. On December 28, 2017, the Partnership issued an additional $125 million 8.50% Senior Notes, as discussed in Note 14 - Debt Obligations.
(2) In certain cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the ARO. In such cases, the ARO 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.
(3) Represents our commitment to certain long-term services contracts.
(4) Not including sublease income of $2.3 million.

For the years ended December 31, 2017, 2016 and 2015, total rental expenses were $12.6 million, $15.9 million and $14.4 million, respectively. The reduction in rental expense observed in 2017 was primarily associated with our divested Propane Business.

21. Related-Party Transactions

To the extent applicable, our discussion below includes the nature of our relationship and activities that we had with our Related Parties, as defined and required by ASC 850 - Related Party Disclosures, in the year ended December 31, 2017 and comparative periods, if applicable. Balances associated with our investments in unconsolidated affiliates are disclosed in Note 10 - Investments in unconsolidated affiliates.

Blackwater Midstream Holdings, LLC

In December 2013, we acquired Blackwater Midstream Holdings, LLC (“Blackwater”) from an affiliate 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. We determined that it was probable the operating targets would be met in 2018 and have kept a $5.0 million accrued distribution to the ArcLight affiliate which is included in Accrued expense and other current liabilities in the accompanying consolidated balance sheets.

Republic Midstream, LLC

Republic Midstream, LLC (“Republic”), is an entity owned by ArcLight in which we charge a monthly fee of approximately $0.1 million. The monthly fee reduced the Corporate expenses in our consolidated statements of operations by $1.0 million for the year ended December 31, 2017. The services agreement with Republic terminated according to its terms in September 2017 and services were no longer provided to Republic. As of December 31, 2017, and 2016, we had a receivable balance due from Republic of $0.8 million and $1.7 million, respectively.

The Partnership also performed certain management services for Republic in exchange for a monthly fee of approximately $75,000. In September 2016, this monthly fee decreased to approximately $40,000 before ceasing in November 2016. For the years ended December 31, 2016 and 2015, the Partnership charged a yearly fee of $0.7 million to Republic for these services. During 2016, the Partnership performed crude transportation and marketing services for Republic. The Partnership charged $3.2 million and $3.0 million for the years ended December 31, 2016 and 2015, respectively, for these crude transportation and marketing services.

American Midstream Lavaca, LLC, a wholly owned, indirect subsidiary of the Partnership (“AMID Lavaca”), in 2015, for administrative convenience, purchased real property and easements that were resold to Republic. On March 9, 2015, AMID Lavaca transferred easements to Republic for $1.5 million, the direct cost to AMID Lavaca of acquiring such easements, and received reimbursement of $1.3 million for capital expenditures incurred in respect of such easements, the direct costs to AMID Lavaca of such expenditures.

American Midstream Bakken, LLC, a wholly owned, indirect subsidiary of the Partnership (“AMID Bakken”) purchased one production unit receipt point measuring package and one truck loading/unloading LACT package from Republic for $0.3 million in September 2015.

Truman Arnold Companies ("TAC")

As a result of the Partnership’s acquisition of the North Little Rock, Arkansas refined product terminal in November 2012, TAC owned common and subordinated units in the Partnership. In addition, Mr. Greg Arnold, President and CEO of TAC, was also a director of the Partnership’s general partner and owned a 5% equity interest in the Partnership’s general partner through October 2016. The Partnership’s refined products terminals and storage segment sold refined products to TAC during 2016. For the year ended December 31, 2016, the Partnership’s revenue from TAC was $0.2 million.

The Partnership’s Propane Marketing Services segment, which was sold in third quarter of 2017, also purchased refined products from TAC. For the years ended December 31, 2016 and 2015, the Partnership paid $1.0 million and $1.1 million, respectively, for refined product purchases from TAC.

General Partner

Employees of our General Partner are assigned to work for us 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 our wholly-owned subsidiary, 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.

In connection with the acquisition of JPE by the Partnership on March 8, 2017, our General Partner agreed to provide quarterly financial support up to a maximum of $25.0 million. The financial support will continue for eight (8) consecutive quarters following the closing of the acquisition, or earlier, until $25.0 million in support has been provided. As of December 31, 2017, we have utilized the full $25.0 million of the financial support.

Separate from the financial support described above, our General Partner also agreed to absorb $17.6 million corporate overhead expenses, which were incurred by and reimbursed to us in 2017. This amount, the amount in the preceding paragraph, and the $3.9 million received related to the General Partner’s ownership percentage, totaled approximately $46.5 million which was presented as part of the contribution line item on our consolidated statements of cash flows. As of December 31, 2017 and 2016, we had $6.5 million and $3.9 million, respectively, of accounts payable due to our General Partner, which has been recorded in Accrued expenses and other current liabilities and relates primarily to compensation. This payable/receivable is generally settled on a quarterly basis related to the foregoing transactions.

Pursuant to the acquisition of JPE, an ArcLight affiliate agreed to reimburse the Partnership for its expenses associated with the transaction. The total amounts reimbursed to the Partnership following the JPE acquisition, was $9.6 million for the year ended December 31, 2017, and was treated as a deemed contribution from ArcLight.

During the years ended December 31, 2016 and 2015, the Partnership's general partner agreed to absorb $9.0 million and $5.5 million of corporate overhead expenses incurred by the Partnership and not pass such expense through to the Partnership. The Partnership received reimbursements for these expenses from its general partner in the quarters subsequent to when they were incurred, which was $7.5 million and $3.0 million for the years ended December 31, 2016 and 2015, respectively. In the first quarter of 2015, certain executive bonuses related to the year ended December 31, 2014 were paid on the Partnership's behalf by ArcLight. In addition, ArcLight reimbursed the Partnership for expenses we incurred for the years ended December 31, 2016 and

2015. The total amounts paid on our behalf or reimbursed to us were $2.4 million and $2.6 million for the years ended December 31, 2016 and 2015, respectively, and were treated as deemed contributions from ArcLight.

On April 20, 2013, our General Partner entered into a reimbursement agreement with HPIP Gonzales Holdings, LLC, an entity controlled by ArcLight ("HPIP Gonzales") under which the general partner received reimbursement for general and administrative costs related to the building of a gathering, processing and salt-water disposal system and a monthly management fee of $55,000. AMID stopped invoicing the management fee on August 1, 2015 and no further services were provided under the agreement. During fiscal year 2015, the Partnership invoiced $0.4 million to HPIP Gonzales under the reimbursement agreement.

JP Development

The Partnership performed certain management services for JP Development LP, an entity controlled by ArcLight ("JP Development"). The Partnership received a monthly fee of $50,000 for these services through 2015 until January 2016. In the year ended December 31, 2015, the Partnership also performed certain additional services for which it received $0.2 million.

JP Development had a pipeline transportation business that provided crude oil pipeline transportation services to the Partnership's discontinued Mid-Continent Business. As a result of utilizing JP Development's pipeline transportation services during the years ended December 31, 2016 and 2015, the Partnership incurred pipeline tariff fees of $0.4 million and $6.0 million, respectively. On February 1, 2016, the Partnership sold certain trucking and marketing assets in the Mid-Continent area to JP Development in connection with JP Development's sale of its GSPP pipeline assets to a third party. During the year ended December 31, 2016, the Partnership's general partner agreed to absorb $9.0 million of corporate overhead expenses incurred by us and not pass such expense through to us. We record non-cash contributions for these expenses in the quarters subsequent to when they were incurred, which was zero for the the year ended December 31, 2017.

On February 1, 2016, the Partnership completed the sale of its crude oil supply and logistics operations in its Mid-Continent region of Oklahoma and Kansas to JP Development in connection with JP Development's sale of its GSPP pipeline assets to a third-party buyer. The sales price was $9.7 million; which included certain adjustments related to inventory and other working capital items.

Transactions with our unconsolidated affiliates

Destin and Okeanos

On November 1, 2016, we became operator of the Destin and Okeanos pipelines and entered into operating and administrative management agreements under which the affiliates pay a monthly fee for general and administrative services provided by us. In addition, the affiliates reimburse us for certain transition related expenses. For the year ended December 31, 2017, we recognized $2.5 million of management fee income. As of December 31, 2017, and 2016, we had an outstanding accounts receivable balance of $0.9 million and $2.2 million, respectively.

AmPan

Prior to August 8, 2017, AmPan was a 60%-owned subsidiary of ours which is consolidated for financial reporting purposes. Panther was the 40% non-controlling interest owner of AmPan. Pursuant to a related party agreement which began in the second quarter of 2016, POGS provided management services to AmPan in exchange for related fees, which in 2016 totaled $0.8 million of Direct operating expenses and $0.4 million of Corporate expenses in our consolidated statement of operations. During January 1, 2017 to August 7, 2017, such management services totaled approximately $0.9 million of Direct operating expenses in our consolidated statement of operations. Effective August 8, 2017, AmPan and POGS became our wholly-owned consolidated subsidiaries. See Note 3 - Acquisitions.

Consolidated Asset Management Services, LLC ("CAMS")

Dan Revers, a director of our General Partner, indirectly owns in excess of 22% of CAMS, which, through various subsidiaries or affiliates, provides pipeline integrity services to the Partnership and subleases an office space from the Partnership. During fiscal years 2017, 2016 and 2015, the Partnership paid CAMS $0.4 million, $0.3 million and $0.6 million, respectively, and received $11 thousand, zero and zero from CAMS, respectively.

Until April 2015, the Partnership received information and technology support from CAMS Bluewire, an affiliate of CAMS. For the year ended December 31, 2015, the Partnership paid $132,000 for IT support and consulting services and for purchases of IT equipment from CAMS Bluewire.

Other Related Party Transactions

Michael D. Rupe, the brother of Ryan Rupe (the Partnership'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"). The Partnership regularly engages in purchases and sales of crude oil and natural gas with CIMA. During fiscal years 2017, 2016 and 2015, the Partnership paid CIMA $5.3 million, $4.3 million and $5.3 million, respectively, and received from CIMA $8.0 million, $3.6 million and $4.7 million in connection with such transactions, respectively.

During September and October 2017 the Partnership made payments on behalf of AMID Merger GP II, LLC related to Propane Business sale totaling $2.5 million. As of December 31, 2017, and 2016, we had an outstanding accounts receivable balance of $2.5 million and $0 million, respectively.

22. Supplemental Cash Flow Information

Supplemental cash flows and non-cash transactions consists of the following (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Supplemental cash flow information			
Cash paid for interest, net of capitalized interest	$65,038	$22,303	$16,540
Cash paid for income taxes	1,041	530	450
Supplemental non-cash information			
Investing			
Increase (decrease) in accrued property, plant and equipment purchases	$(3,553)	$8,533	$(21,841)
Assets acquired under capital lease	—	139	—
Excess of carrying value of interest in Destin above consideration paid	278	—	—
Financing			
Contributions from an affiliate holding limited partner interests	$4,000	$7,500	$4,350
Acquisitions partially funded by the issuance of common units	12,532	—	3,442
Issuance of Series C Units and Warrant in connection with the Emerald Transactions	—	120,000	—
Debt assumed in connection with the Trans-Union acquisition	32,453	—	—
Accrued cash distributions on convertible preferred units	—	7,103	—
Paid-in-kind distributions on convertible preferred units	17,565	14,446	16,978
Paid-in-kind distributions on Series B Units	—	—	1,373
Cancellation of escrow units	—	6,817	—
Accrued distributions to NCI holders	(1,342)	—	—
Accrued distribution from an unconsolidated affiliate	—	5,000	—

23. Reportable Segments

Overview

Our operations are located in the United States and are organized into the following five reportable segments: Gas Gathering and Processing Services, Liquid Pipelines and Services, Natural Gas Transportation Services, Offshore Pipeline and Services, and Terminalling Services. These segments, are described below, have been identified based on the differing products and services, regulatory environments and the expertise required for these operations.

Gas Gathering and Processing Services 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.

Liquid Pipelines and Services provides transportation, purchase and sales of crude oil from various receipt points including lease automatic custody transfer ("LACT") facilities and delivering to various markets.

Natural Gas Transportation Services 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.

Offshore Pipelines and Services gathers and transports natural gas from various receipt points to other pipeline interconnects, onshore facilities and other delivery points.

Terminalling Services 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 and also includes crude oil storage in Cushing, Oklahoma and refined products terminals in Texas and Arkansas.

Segment Gross Margin per Segment

Our Chief Executive Officer serves as our Chief Operating Decision Maker and evaluates the performance of our reportable segments primarily on the basis of segment gross margin, which is our segment measure of profitability. We define segment gross margin for each segment as summarized below:

Gas Gathering and Processing Services - total revenue plus unconsolidated affiliate earnings less unrealized gains (losses) on commodity derivatives, construction and operating management agreement income and less the cost of sales.

Liquid Pipelines and Services - total revenue plus unconsolidated affiliate earnings less unrealized gains (losses) on commodity derivatives and construction and operating management agreement income less the cost of sales. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

Natural Gas Transportation Services - total revenue plus unconsolidated affiliate earnings and construction and operating management agreement income less the cost of sales. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

Offshore Pipelines and Services - total revenue plus unconsolidated affiliate earnings less the cost of sales. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

Terminalling Services - total revenue less cost of sales and direct operating expense which includes direct labor, general materials and supplies and direct overhead.

The following tables set forth our segment financial information for the periods indicated:

	December 31, 2017					
	Gas Gathering and Processing Services	Liquid Pipelines and Services	Natural Gas Transportation Services	Offshore Pipelines and Services	Terminalling Services	Total
	(in thousands)					
Commodity sales	$124,853	$319,870	$ 25,376	$11,508	$ 15,295	$496,902
Services	21,900	16,412	22,637	43,517	50,186	154,652
Gains (losses) on commodity derivatives, net	310	(429)	—	—	—	(119)
Total revenue	147,063	335,853	48,013	55,025	65,481	651,435
Earnings in unconsolidated affiliates	—	5,113	—	57,937	—	63,050
Cost of sales	98,177	312,830	24,211	9,298	12,855	457,371
Direct operating expenses	32,003	12,330	6,311	16,973	14,639	82,256
Corporate expenses						112,058
Depreciation, amortization, and accretion						103,448
Gain on sale of assets, net						(4,063)
Impairment of long-lived assets / intangible assets						116,609
Loss on impairment of goodwill						77,961
Total operating expenses						945,640
Interest expense						66,465
Other income						(36,254)
Income tax expense						1,235
Loss from continuing operations						(262,601)
Income from discontinued operations, net of tax						44,095
Net loss						(218,506)
Net income attributable to non-controlling interests						4,473
Net loss attributable to Partnership						$(222,979)
Segment gross margin	$49,010	$27,999	$ 23,424	$103,664	$ 37,987	

	December 31, 2016					
	Gas Gathering and Processing Services	Liquid Pipelines and Services	Natural Gas Transportation Services	Offshore Pipelines and Services	Terminalling Services	Total
	(in thousands)					
Commodity sales	$91,444	$304,502	$ 21,999	$6,812	$ 14,655	$439,412
Services	22,558	19,063	18,109	40,502	50,999	151,231
Losses on commodity derivatives, net	(833)	(341)	—	(7)	(436)	(1,617)
Total revenue	113,169	323,224	40,108	47,307	65,218	589,026
Earnings in unconsolidated affiliates	—	2,070	—	38,088	—	40,158
Cost of sales	63,832	293,618	21,288	3,049	11,564	393,351
Direct operating expenses	33,802	10,091	5,923	10,945	10,783	71,544
Corporate expenses						89,438
Depreciation, amortization, and accretion						90,882
Loss on sale of assets, net						688
Impairment of long-lived assets / intangible assets						697
Impairment of goodwill						2,654
Total operating expenses						649,254
Interest expense						21,433
Other income						(254)
Income tax expense						2,580
Loss from continuing operations						(43,829)
Loss from discontinued operations, net of tax						(4,715)
Net loss						(48,544)
Net income attributable to non-controlling interests						2,766
Net loss attributable to Partnership						$(51,310)
Segment gross margin	$48,245	$31,556	$ 18,616	$82,346	$ 42,872	

	December 31, 2015					
	Gas Gathering and Processing Services	Liquid Pipelines and Services	Natural Gas Transportation Services	Offshore Pipelines and Services	Terminalling Services	Total
	(in thousands)					
Commodity sales	$107,680	$457,448	$ 23,972	$ 13,798	$ 10,343	$613,241
Services	30,196	23,008	16,035	21,457	45,022	135,718
Gains on commodity derivatives, net	1,240	—	—	84	21	1,345
Total revenue	139,116	480,456	40,007	35,339	55,386	750,304
Earnings in unconsolidated affiliates	—	—	—	8,201	—	8,201
Cost of sales	72,960	454,057	21,858	9,914	8,893	567,682
Direct operating expenses	35,250	9,912	6,728	9,425	10,414	71,729
Corporate expenses						65,327
Depreciation, amortization, and accretion						81,335
Loss on sale of assets, net						2,860
Impairment of goodwill						148,488
Total operating expenses						937,421
Interest expense						20,077
Other income						(1,460)
Income tax expense						1,885
Loss from continuing operations						(199,418)
Loss from discontinued operations, net of tax						(423)
Net loss						(199,841)
Net loss attributable to non-controlling interests						(13)
Net loss attributable to Partnership						$(199,828)
Segment gross margin	$65,692	$26,399	$ 18,073	$33,613	$ 36,079	

A reconciliation of total assets by segment to the amounts included in the consolidated balance sheets is as follows:

	December 31,	
	2017	2016
Segment assets:	(in thousands)	
Gas Gathering and Processing Services	$404,872	$530,889
Liquid Pipelines and Services	359,646	425,389
Natural Gas Transportation Services	268,991	221,604
Offshore Pipelines and Services	553,213	400,193
Terminalling Services	293,085	299,534
Other [1]	43,659	334,953
Discontinued operations	—	136,759
Total assets	$1,923,466	$2,349,321

[1] Other assets not allocable to segments consist of restricted cash, corporate leasehold improvements and other miscellaneous assets.

24. Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2017 and 2016 are as follows (in thousands, except per unit amounts):

	First Quarter (4)	Second Quarter (4)	Third Quarter	Fourth Quarter (1)(2)(3)
Year Ended December 31, 2017				
Total revenues	$164,078	$162,030	$162,290	$163,037
Operating loss	(24,457)	(25,574)	(20,616)	(223,558)
Net income (loss) from continuing operations, net of tax	(28,171)	(25,901)	11,806	(220,335)
Income (loss) from discontinued operations, net of tax	(710)	(1,801)	44,696	1,910
Net income attributable to noncontrolling interest	1,303	1,462	621	1,087
Net income (loss) attributable to the Partnership	(30,184)	(29,164)	55,881	(219,512)
General Partner's Interest in net income (loss)	(420)	(375)	697	(2,883)
Limited Partners' Interest in net income (loss)	$(29,764)	$(28,789)	$55,184	$(216,629)
Limited Partners' income (loss) per unit:				
Income (loss) from continuing operations	$(0.75)	$(0.69)	$0.05	$(4.31)
Income (loss) from discontinued operations	$(0.02)	$(0.03)	$0.86	$0.04
Net income (loss)	$(0.77)	$(0.72)	$0.91	$(4.27)
Year Ended December 31, 2016				
Total revenues	$100,998	$152,253	$159,903	$175,872
Operating loss	(16,097)	(12,790)	(9,724)	(21,617)
Net loss from continuing operations, net of tax	(17,772)	(12,156)	(5,488)	(8,413)
Income (loss) from discontinued operations, net of tax	7,169	2,675	(2,310)	(12,249)
Net income (loss) attributable to noncontrolling interest	(3)	954	1,241	574
Net loss attributable to the Partnership	(10,600)	(10,435)	(9,039)	(21,236)
General Partner's Interest in net loss	(97)	(107)	(31)	2
Limited Partners' Interest in net loss	$(10,503)	$(10,328)	$(9,008)	$(21,238)
Limited Partners' income (loss) per unit:				
Loss from continuing operations	$(0.49)	$(0.40)	$(0.29)	$(0.33)
Income (loss) from discontinued operations	0.16	0.07	(0.05)	(0.27)
Net loss	$(0.33)	$(0.33)	$(0.34)	$(0.60)

(1) We recognized goodwill impairment charges of $78.0 million and $2.7 million in the fourth quarters of 2017 and 2016, respectively. See Note 10 - Goodwill and Intangible Assets, Net for more information.

(2) We recognized asset impairment charges of $116.6 million and $0.7 million in the fourth quarters of 2017 and 2016, respectively. Of these $116.6 million impairment charges in 2017, $103.9 million are related to our property, plant and equipment and $12.7 million are related to intangible assets, as discussed in Note 9 - Property, Plant and Equipment and Note 10 - Goodwill and Intangible Assets, Net.

(3) Total revenues and cost of sales for the fourth quarter of 2017 have been reduced by approximately $13.7 million primarily due to an out-of-period adjustment recorded during the quarter related to an error in gross versus net revenue recognition. This adjustment did not have a material impact to revenue for any prior quarters and had no impact to operating loss, net income (loss) or segment margin for any period.

(4) Our quarterly selected data have been recasted to reflect the sale of the Propane Business on September 1, 2017. For more information, see Note 4 - Discontinued Operations.

25. Subsequent Events

Distribution

On January 26, 2018, 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, 2017, or $1.65 per common unit on an annualized basis. The distribution was paid on February 14, 2018, to unitholders of record as of the close of business February 7, 2018.

Sales of the Refined Products Business

On February 16, 2018, the Partnership entered into a definitive agreement for the sale of the Refined Products Terminals (the "Refined Products Business") to DKGP Energy Terminals LLC, a joint venture between Delek Logistics Partners, LP and Green Plains Partners LP, for approximately $138.5 million in cash, subject to working capital adjustments. Closing of the sale of the Refined Products Business is subject to customary closing conditions, including clearance under the Hart-Scott-Rodino Act.
The transaction is expected to close in the first half of 2018. The Refined Products Business consists of two terminal facilities, located in Caddo Mills, Texas ("Caddo Mills") and North Little Rock, Arkansas ("NLR").
Southcross Unitholder Approval of Merger

On March 27, 2018, a majority of the common unitholders of Southcross Energy Partners, L.P. voted to approve the previously announced proposed merger with the Partnership. The closing of the merger remains subject to certain state level regulatory approvals and the closing conditions described in the definitive proxy statement filed with the Securities and Exchange Commission on February 13, 2018. The merger is expected to close later in the second quarter of 2018.

Delta House Capital Contribution Agreement

On March 11, 2018, the Partnership and Magnolia, an affiliate of ArcLight, entered into a Capital Contribution Agreement to provide additional capital and corporate overhead support to the Partnership during the first three quarters of 2018 in connection with temporary curtailment of production flow at Delta House. Pursuant to the Agreement, Magnolia has agreed to provide support to the Partnership in an amount to be agreed, up to the difference between the actual cash distribution received by the Partnership on account of its interest in Delta House and the quarterly cash distribution expected to be received if production flow to Delta House had not been not curtailed.