American Midstream Partners, LP
Form 10-Q
May 15, 2017

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

FORM 10-Q
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended
March 31, 2017
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-35257

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, TX	77042
(Address of principal executive offices)	(Zip code)

(346) 241-3400
(Registrant's telephone number, including area code)

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. ý Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes ¨ No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
¨ Yes ý No

There were 51,730,964 common units, 10,266,642 Series A Units, 8,792,205 Series C Units and 2,333,333 Series D Units of American Midstream Partners, LP outstanding as of May 5, 2017. Our common units trade on the New York Stock Exchange under the ticker symbol "AMID."

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Glossary of Terms

As generally used in the energy industry and in this Quarterly Report on Form 10-Q (the "Quarterly Report"), the identified terms have the following meanings:

Bbl	Barrels: 42 U.S. gallons measured at 60 degrees Fahrenheit.
Bbl/d	Barrels per day.
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	Thousand gallons per day.
MBbl	Thousand barrels.
MMBbl	Million barrels.
MMBbl/day	Million barrels per day.
MMBtu	Million British thermal units.
Mcf	Thousand cubic feet.
MMcf	Million cubic feet.
MMcf/d	Million cubic feet per day.
NGL or NGLs	Natural gas liquid(s): The combination of ethane, propane, normal butane, isobutane and natural gasoline that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Tcf	Trillion cubic feet.
Throughput	

The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

As used in this Quarterly 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.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Balance Sheets
(Unaudited, in thousands, except unit amounts)

	March 31, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$16,919	$5,666
Restricted cash	22,294	—
Accounts receivable, net of allowance for doubtful accounts of $2,480 and $1,871, respectively	24,770	27,769
Unbilled revenue	57,865	55,646
Inventory	9,614	6,776
Other current assets	28,012	27,667
Total current assets	159,474	123,524
Risk management assets - long term	9,624	10,664
Property, plant and equipment, net	1,142,302	1,145,003
Goodwill	217,498	217,498
Restricted cash- long term	5,037	323,564
Intangible assets, net	218,015	225,283
Investment in unconsolidated affiliates	284,896	291,988
Other assets, net	9,397	11,797
Total assets	$2,046,243	$2,349,321
Liabilities, Equity and Partners' Capital		
Current liabilities		
Accounts payable	$37,833	$45,278
Accrued gas purchases	10,294	7,891
Accrued expenses and other current liabilities	80,887	81,284
Current portion of debt	3,223	5,485
Total current liabilities	132,237	139,938
Asset retirement obligations	44,809	44,363
Other liabilities	2,250	2,030
3.77% Senior notes (Non - Recourse)	55,895	55,979
8.50% Senior notes	292,200	291,309
Revolving credit agreement	644,842	888,250
Deferred tax liability	8,883	8,205
Total liabilities	1,181,116	1,430,074
Commitments and contingencies (See Note 16)		
Convertible preferred units	336,271	334,090
Equity and partners' capital		
General Partner interests (688 thousand and 680 thousand units issued and outstanding as of March 31, 2017 and December 31, 2016, respectively)	(47,055)	(47,645)
Limited Partner interests (51,631 thousand and 51,351 thousand units issued and outstanding as of March 31, 2017 and December 31, 2016, respectively)	558,463	616,087
Accumulated other comprehensive income (loss)	(22)	(40)
Total partners' capital	511,386	568,402
Noncontrolling interests	17,470	16,755

Total equity and partners’ capital	528,856	585,157
Total liabilities, equity and partners’ capital	$2,046,243	$2,349,321

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

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

	Three months ended March 31, 2017	2016
Revenue:		
Commodity sales	$158,501	$107,570
Services	41,388	36,044
Gain (loss) on commodity derivatives, net	(257)	(238)
Total revenue	199,632	143,376
Operating expenses:		
Costs of sales	132,785	73,938
Direct operating expenses	30,088	30,575
Corporate expenses	32,844	21,101
Depreciation, amortization and accretion expense	29,351	25,041
(Gain) loss on sale of assets, net	(228)	1,122
Total operating expenses	224,840	151,777
Operating loss	(25,208)	(8,401)
Other income (expense), net		
Interest expense	(17,966)	(8,302)
Other income (expense)	14	31
Earnings in unconsolidated affiliates	15,402	7,343
Loss from continuing operations before taxes	(27,758)	(9,329)
Income tax expense	(1,123)	(735)
Loss from continuing operations	(28,881)	(10,064)
Loss from discontinued operations, net of tax	—	(539)
Net loss	(28,881)	(10,603)
Less: Net income (loss) attributable to noncontrolling interests	1,303	(3)
Net loss attributable to the Partnership	$(30,184)	$(10,600)
General Partner’s interest in net loss	$(420)	$(97)
Limited Partners’ interest in net loss	$(29,764)	$(10,503)
Distribution declared per common unit [(1)]	$0.4125	$0.4725
Limited Partners’ net loss per common unit (See Note 14):		
Basic and diluted:		
Loss from continuing operations	$(0.75)	$(0.32)
Loss from discontinued operations	—	(0.01)
Net loss	$(0.75)	$(0.33)
Weighted average number of common units outstanding:		
Basic and diluted	51,451	50,925

(1) Declared and paid each quarter related to prior quarter’s earnings.

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

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American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income (Loss)
(Unaudited, in thousands)

	Three months ended March 31,	
	2017	2016
Net loss	$(28,881)	$(10,603)
Unrealized gain (loss) related to postretirement benefit plan	18	14
Comprehensive loss	(28,863)	(10,589)
Less: Comprehensive income (loss) attributable to noncontrolling interests	1,303	(3)
Comprehensive loss attributable to the Partnership	$(30,166)	$(10,586)

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

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American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Changes in Partners' Capital
and Noncontrolling Interests
(Unaudited, in thousands)

	General Partner Interests	Limited Partner Interests	Series B Convertible Units	Accumulated Other Comprehensive Income (Loss)	Total Partners' Capital	Non controlling Interests
Balances at December 31, 2015	$(47,091)	$753,388	$ 33,593	$ 40	$739,930	$ 12,111
Net loss	(97)	(10,503)	—	—	(10,600)	(3)
Issuance of common units, net of offering costs	—	(104)	—	—	(104)	—
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—
Conversion of Series B units	—	33,593	(33,593)	—	—	—
Contributions	92	2,500	—	—	2,592	—
Distributions	(2,087)	(31,412)	—	—	(33,499)	—
Contributions from noncontrolling interest owners	—	—	—	—	—	85
LTIP vesting	(2,041)	2,041	—	—	—	—
Tax netting repurchase	—	(150)	—	—	(150)	—
Equity compensation expense	1,084	559	—	—	1,643	—
Post-retirement benefit plan	—	—	—	14	14	—
Addition of Mesquite NCI		—	—	—	—	210
Balances at March 31, 2016	$(50,140)	$743,095	$ —	$ 54	$693,009	$ 12,403
Balances at December 31, 2016	$(47,645)	$616,087	$ —	$ (40)	$568,402	$ 16,755
Net income (loss)	(420)	(29,764)	—	—	(30,184)	1,303
Issuance of common units, net of offering costs	—	(72)	—	—	(72)	—
Contributions	123	4,000	—	—	4,123	—
Distributions	(282)	(33,685)	—	—	(33,967)	—
Contributions from noncontrolling interests owners	—	—	—	—	—	280
Distributions to noncontrolling interests owners	—	—	—	—	—	(868)
LTIP vesting	(2,135)	2,135	—	—	—	—
Tax netting repurchase	—	(971)	—	—	(971)	—
Equity compensation expense	3,304	733	—	—	4,037	—
Other comprehensive income	—	—	—	18	18	—
Balances at March 31, 2017	$(47,055)	$558,463	$ —	$ (22)	$511,386	$ 17,470

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

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American Midstream Partners, LP and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(Unaudited, in thousands)

	Three months ended March 31,	
	2017	2016
Cash flows from operating activities		
Net loss	$(28,881)	$(10,603)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, amortization and accretion expense	29,351	25,252
Amortization of deferred financing costs	1,253	702
Amortization of weather derivative premium	257	219
Unrealized loss on derivatives contracts, net	1,273	1,382
Non-cash compensation expense	4,037	1,643
(Gain) loss on sale of assets, net	(228)	1,008
Corporate overhead support	4,000	2,500
Other non-cash items	1,965	41
Earnings in unconsolidated affiliates	(15,402)	(7,343)
Distributions from unconsolidated affiliates	15,402	7,343
Deferred tax expense	678	294
Allowance for bad debts	830	(6)
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	1,285	340
Inventory	(2,626)	(5,592)
Unbilled revenue	(1,019)	18,833
Other current assets	3,114	6,720
Other assets, net	168	226
Restricted cash	(3,135)	—
Accounts payable	(9,716)	(10,909)
Accrued gas purchases	2,403	(749)
Accrued expenses and other current liabilities	994	(1,359)
Asset retirement obligations	(41)	—
Other liabilities	(195)	(674)
Net cash provided by operating activities	5,767	29,268
Cash flows from investing activities		
Additions to plant, property and equipment	(20,221)	(26,319)
Proceeds from disposals of plant, property and equipment	51	11,126
Insurance proceeds from involuntary conversion of property, plant and equipment	150	—
Investment in unconsolidated affiliates	—	(3,546)
Distributions from unconsolidated affiliates, return of capital	7,092	6,172
Change in restricted cash	299,313	—
Net cash provided by (used in) investing activities	286,385	(12,567)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	(72)	(104)
Contributions	123	92
Distributions	(32,198)	(29,028)
Contribution from noncontrolling interest owners	280	85
Distributions to noncontrolling interests owners	(868)	—

LTIP tax netting unit repurchase	(971)	(150)
Payment of financing costs	(1,402)	(323)
Payments on other debt	(2,363)	(844)
Borrowings on other debt	—	867
Payments on credit agreement	(325,908)	(59,450)
Borrowings on credit agreement	82,500	71,750
Other	(20)	(44)

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	Three months ended March 31,	
	2017	2016
Net cash used in financing activities	(280,899)	(17,149)
Net increase (decrease) in cash and cash equivalents	11,253	(448)
Cash and cash equivalents		
Beginning of period	5,666	1,987
End of period	$16,919	$1,539

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

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American Midstream Partners, LP and Subsidiaries
Notes to Condensed Consolidated Financial Statements
(Unaudited)

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

General

American Midstream Partners, LP (the “Partnership”, “we”, “us”, or “our”) is a growth-oriented Delaware limited partnership that was formed on August 20, 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. The Partnership’s general partner, American Midstream GP, LLC (the “General Partner”), is 77% owned by High Point Infrastructure Partners, LLC (“HPIP”) and 23% 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.

Merger with JPE

On March 8, 2017, we completed the acquisition of JP Energy Partners LP (“JPE”), an entity controlled by ArcLight affiliates, in a unit-for-unit merger (“JPE Acquisition”). In connection with the transaction, we issued approximately 20.2 million common units to holders of the JPE common and subordinated units, including 9.8 million common units to ArcLight affiliates. In connection with the completion of the Acquisition, we entered into a supplemental indenture pursuant to which the JPE Entities jointly and severally, fully and unconditionally, guarantee the 8.50% Senior Notes.

As both we and JPE were controlled by ArcLight affiliates, the acquisition represents a transaction among entities under common control. Although we are the legal acquirer, JPE was considered the acquirer for accounting purposes as ArcLight obtained control of JPE prior to obtaining control of us on April 15, 2013. As a result, we adjusted our historical financial statements to reflect ArcLight’s acquisition cost basis back to April 15, 2013. In addition, the accompanying financial statements and related notes have been retrospectively adjusted to include the historical results of JPE prior to the effective date of the JPE Acquisition. The accompanying financial statements and related notes present the combined financial position, results of operations, cash flows and equity of JPE at historical cost.

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 six reportable segments, (1) gas gathering and processing services, (2) liquids pipelines and services, (3) natural gas transportation services, (4) offshore pipelines and services, (5) terminalling services and (6) propane marketing 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; storing specialty chemical products; and distributing and selling propane 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. Our propane marketing services include commercial and retail operations across 46 of the lower 48 states.

Basis of presentation

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2016, except that the consolidated financial statements have been retrospectively adjusted to reflect the consolidation of JPE, as discussed above. The results of operations for the three months ended March 31, 2017 is not necessarily indicative of results expected for the full year. In the opinion of our management, such financial information reflects all adjustments necessary for a fair statement of the financial position and the results of operations for such interim periods in accordance with GAAP. All such adjustments are of a normal recurring nature. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Transactions between entities under common control

We may enter into transactions with ArcLight affiliates whereby we receive midstream assets or other businesses in exchange for cash or Partnership equity. We account for the net assets acquired at the affiliate's historical cost basis as the transactions are between entities under common control. In certain cases, our historical financial statements will be revised to include the results attributable to the assets acquired from the later of June 2011 (the date Arclight affiliates obtained control of JPE) or the date the ArcLight affiliate obtained control of the assets acquired.

Use of estimates

When preparing consolidated financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and assumptions are based on information available at the time such estimates and assumptions are made. Adjustments made with respect to the use of these estimates and assumptions often relate to information not previously available. Uncertainties with respect to such estimates and assumptions are inherent in the preparation of financial statements. Estimates and assumptions are used in, among other things, i) estimating unbilled revenues, product purchases and operating and general and administrative costs, ii) developing fair value assumptions, including estimates of future cash flows and discount rates, iii) analyzing long-lived assets, goodwill and intangible assets for possible impairment, iv) estimating the useful lives of assets and v) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Cash, cash equivalents and restricted cash

We consider all highly liquid investments with an original maturity of three months or less at the date of purchase to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

From time to time we are required to maintain cash in separate accounts the use of which is restricted by the terms of our debt agreements, asset retirement obligations, contracted arrangements and management restrictions. Such amounts are included in Restricted cash in our condensed consolidated balance sheets.

Allowance for doubtful accounts

We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of March 31, 2017 and December 31, 2016, we recorded allowances for doubtful accounts of $2.5 million and $1.9 million, respectively.

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 condensed 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.

Revenue recognition

We recognize revenue from the sale of commodities (e.g., natural gas, crude oil, NGLs, refined products 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.

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Revenue-related taxes collected from customers and remitted to taxing authorities, principally sales taxes, are presented on a net basis within the consolidated statements of operations.

New Accounting Pronouncements

Accounting Standards Issued Not Yet Adopted

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606)”, which amends the existing accounting guidance for revenue recognition. The update requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU No. 2015-14 was subsequently issued and deferred the effective date to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that period. In March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal Versus Agent Considerations, as further clarification on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing as further clarification on identifying performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, as clarifying guidance on specific narrow scope improvements and practical expedients. We are in the process of reviewing our various customer arrangements in order to determine the impact that these updates will have on our consolidated financial statements and related disclosures. We have engaged a third-party consultant to assist with our review and are still in the process of evaluating the method of adoption for transitioning to the new standard.

In February 2016, the FASB issued ASU No. 2016-02 (Topic 842) "Leases" which supersedes the lease recognition requirements in Accounting Standards Codification Topic 840, "Leases". Under ASU No. 2016-02 lessees are required to recognize assets and liabilities on the balance sheet for most leases and provide enhanced disclosures. Leases will continue to be classified as either finance or operating. ASU No. 2016-02 is effective for annual reporting periods, and interim periods within those years beginning after December 15, 2018. Entities are required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements, and there are certain optional practical expedients that an entity may elect to apply. Full retrospective application is prohibited and early adoption by public entities is permitted. Based upon our evaluation to date, we anticipate that the adoption of ASU 2016-02 will have a material effect on our consolidated financial statements as we will be required to reflect our various lease obligations and associated asset use rights on our consolidated balance sheets. The adoption may also impact our debt covenant compliance and may require us to modify or replace certain of our existing information systems. We have not yet determined the timing or manner in which we will implement the updated guidance.

In August 2016, the FASB issued ASU No. 2016-15, “Statement of Cash Flows (Topic 320): Classification of Cash Receipts and Cash Payments”, which addresses eight specific cash flow issues with the objective of reducing the existing diversity of presentation and classification in the statement of cash flows. ASU No. 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal periods. Early adoption is permitted, but only if all aspects are adopted in the same period. We are currently evaluating the impact this update will have on our consolidated statements of cash flows and related disclosures.

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 update is effective beginning first quarter of 2018. Early adoption is permitted, but it must occur in the first interim period. Any adjustments required in early adoption of this update should be reflected as of the beginning of the fiscal year that includes the interim period and should be applied using a retrospective transition method to each period. We are currently evaluating the impact that this update will have on our consolidated statement of cash flows and related disclosures.

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 a “set” (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. The adoption of ASU 2017-01 is not expected to have a material impact on our consolidated financial statements and related disclosures associated with acquisitions subsequent to the effective date.

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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 are currently evaluating the impact this update will have on our consolidated financial statements and related disclosures.

2. Acquisitions

JP Energy Partners LP

On March 8, 2017, we completed the merger of JPE, an entity controlled by ArcLight affiliates, in a unit-for-unit merger. In connection with the transaction, each JPE common or subordinated unit held by investors not affiliated with ArcLight was converted into the right to receive 0.5775 of a Partnership common unit, and each JPE common or subordinated unit held by ArcLight affiliates was converted into the right to receive 0.5225 of a Partnership common unit. We issued a total of 20.2 million of common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates.

As both we and JPE were controlled by ArcLight affiliates, the acquisition represents a transaction among entities under common control and will be accounted for as a common control transaction. Although we are the legal acquirer, JPE is considered to be the acquirer for accounting purposes as ArcLight obtained control of JPE prior to obtaining control of the Partnership on April 15, 2013. As a result, JPE will record the acquisition of the Partnership at ArcLight’s historical cost basis.

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

3. Inventory

Inventory consists of the following as of March 31, 2017 and December 31, 2016 (in thousands):

	March 31, 2017	December 31, 2016
Crude oil	$3,969	$ 1,216
NGLs	3,505	3,482
Refined products	439	291
Materials, supplies and equipment	1,701	1,787
Total inventory	$9,614	$ 6,776

4. Other Current Assets

Other current assets consist of the following (in thousands):

	March 31, 2017	December 31, 2016

Prepaid insurance	$7,729	$ 9,702
Insurance receivables	7,574	2,895
Due from related parties	7,083	4,805
Other receivables	3,928	2,998
Risk management assets	534	964
Other assets	1,164	6,303
Total	$28,012	$ 27,667

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5. Risk Management Activities

We are exposed to certain market risks related to the volatility of commodity prices and changes in interest rates. To monitor and manage these market risks, we have established comprehensive risk management policies and procedures. We do not enter into derivative instruments for any purpose other than hedging commodity price risk, interest rate risk, and weather risk. We do not speculate using derivative instruments.

Commodity Derivatives

Our normal business activities expose us to risks associated with changes in the market price of crude oil and natural gas, among other commodities. Management believes it is prudent to limit our exposure to these risks, which include our (i) propane purchases, (ii) pre-existing or anticipated physical crude oil and refined product sales and (iii) certain crude oil held in inventory. To meet this objective, we use a combination of fixed price swap and forward contracts. Our forward contracts that qualify for the Normal Purchase Normal Sale ("NPNS") exception under GAAP are recognized when the underlying physical transaction is delivered. While these contracts are considered derivative financial instruments under ASC 815, they are not recorded at fair value, but on an accrual basis of accounting. If it is determined that a transaction designated as NPNS no longer meets the scope exception, the fair value of the related contract is recorded on the balance sheet and immediately recognized through earnings.

We measure our commodity derivatives at fair value using the income approach which discounts the future net cash settlements expected under the derivative contracts to a present value. These valuations utilize indirectly observable ("Level 2") inputs, including contractual terms and commodity prices observable at commonly quoted intervals.

The following table summarizes the net notional volume purchases (sales) of our outstanding commodity-related derivatives, excluding those contracts that qualified for the NPNS exception as of March 31, 2017 and December 31, 2016, none of which were designated as hedges for accounting purposes.

	March 31, 2017		December 31, 2016	
Commodity Swaps	Volume	Maturity	Volume	Maturity
Propane Fixed Price (Gallons)	7,767,296	April 30,2017 - December 31, 2019	4,364,880	January 31, 2017 - November 30, 2018
Crude Oil Fixed Price (Barrels)	61,000	May 31, 2017 - June 30, 2017	—	—
Crude Oil Basis (Barrels)	—	—	180,000	January 25, 2017- March 25, 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 March 31, 2017, our outstanding interest rate swap contracts consist of the following (in thousands):

Notional Amount	Term	Fair Value
$100,000	April 1, 2017 through December 29, 2017	$101
$100,000	December 29, 2017 through January 29, 2019	$287
$200,000	April 1, 2017 through September 3, 2019	$2,092
$100,000	January 1, 2018 through December 31, 2021	$2,847
$150,000	January 1, 2018 through December 31, 2022	$4,732

$10,059

The fair value of our interest rate swaps was estimated using a valuation methodology based upon forward interest rate and volatility curves as well as other relevant economic measures, if necessary. Discount factors may be utilized to extrapolate a forecast of future cash flows associated with long dated transactions or illiquid market points. The inputs, which represent Level 2 inputs in the valuation hierarchy, are obtained from independent pricing services and we have made no adjustments to those prices.

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Weather Derivative

In the second quarter of 2016, we entered into a weather derivative to mitigate the impact of potential unfavorable weather on our operations under which we could receive payments totaling up to $30.0 million in the event that a hurricane of certain strength pass through the areas identified in the derivative 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 no premiums during the three months ended March 31, 2017 and 2016, respectively. Premiums are amortized to Direct operating expenses on a straight-line basis over the 1 year term of the contract. Unamortized amounts associated with the weather derivatives were approximately $0.2 million and $0.4 million as of March 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 values of our derivative contracts (before netting adjustments) included in the condensed consolidated balance sheets as of March 31, 2017 and December 31, 2016 (in thousands):

		Asset Derivatives		Liability Derivatives	
Type	Balance Sheet Classification	March 31, 2017	December 31, 2016	March 31, 2017	December 31, 2016
Commodity swaps	Other current assets	$ 200	$ 607	$ —	$ —
Commodity swaps	Accrued expenses and other current liabilities	—	—	(316)	(1)
Commodity swaps	Risk management assets - long term	3	37	—	—
Commodity swaps	Other liabilities	—	—	(201)	(1)
Interest rate swaps	Other current assets	337	—	—	—
Interest rate swaps	Accrued expenses and other current liabilities	—	—	—	(252)
Interest rate swaps	Risk management assets- long term	9,722	10,628	—	—
Weather derivatives	Other current assets	$ 172	$ 429	$ —	$ —

The following tables present the fair value of our recognized derivative assets and liabilities on a gross basis and amounts offset in the condensed consolidated balance sheets as of March 31, 2017 and December 31, 2016 that are subject to enforceable master netting arrangements (in thousands):

	Gross Risk Management Position		Netting Adjustments		Net Risk Management Position presented in the balance sheet	
Balance Sheet Classification	March 31, 2017	December 31, 2016	March 31, 2017	December 31, 2016	March 31, 2017	December 31, 2016
Other current assets	$ 709	$ 1,036	$ (175)	$ (72)	$ 534	$ 964
Risk management assets- long term	9,725	10,665	(101)	(1)	9,624	10,664
Total assets	$ 10,434	$ 11,701	$ (276)	$ (73)	$ 10,158	$ 11,628
Accrued expenses and other liabilities	$ (316)	$ (253)	$ 175	$ 72	$ (141)	$ (181)
Other liabilities	(201)	(1)	101	1	(100)	—
Total liabilities	$ (517)	$ (254)	$ 276	$ 73	$ (241)	$ (181)

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For the three months ended March 31, 2017 and 2016, respectively, the realized and unrealized gains (losses) associated with our commodity, interest rate and weather derivative instruments were recorded in our unaudited condensed consolidated statements of operations as follows (in thousands):

	Realized	Unrealized
2017		
Gains (losses) on commodity derivatives, net	$ 699	$ (956)
Interest expense	(65)	(317)
Direct operating expenses	(257)	—
Total	$ 377	$ (1,273)
2016		
Gains (losses) on commodity derivatives, net	$ (388)	$ 150
Interest expense	—	(1,532)
Direct operating expenses	(219)	—
Total	$ (607)	$ (1,382)

6. Property, Plant and Equipment, Net

Property, plant and equipment, net, consists of the following (in thousands):

	Useful Life (in years)	March 31, 2017	December 31, 2016
Land	N/A	$21,390	$21,811
Construction in progress	N/A	117,288	131,449
Buildings and improvements	4 to 40	24,407	24,323
Transportation equipment	5 to 15	45,519	44,060
Processing and treating plants	8 to 40	139,553	137,014
Pipelines, compressors and right-of-way	3 to 40	776,867	754,911
Storage	3 to 40	210,685	210,579
Equipment	3 to 31	107,715	104,235
Total property, plant and equipment		1,443,424	1,428,382
Accumulated depreciation		(301,122)	(283,379)
Property, plant and equipment, net		$1,142,302	$1,145,003

At March 31, 2017 and December 31, 2016, gross property, plant and equipment included $305.1 million and $291.1 million, respectively, related to our FERC regulated interstate and intrastate assets.

Depreciation expense totaled $21.6 million and $19.7 million for the three months ended March 31, 2017 and 2016, respectively. Capitalized interest was $1.0 million and $0.5 million for the three months ended March 31, 2017 and 2016, respectively.

7. Goodwill and Intangible Assets, Net

Goodwill as of March 31, 2017 and December 31, 2016 consisted of the following (in thousands):

	March 31, 2017	December 31, 2016
Liquids Pipelines and Services	$124,710	$124,710
Terminalling Services	77,425	77,425
Propane Marketing Services	15,363	15,363
	$217,498	$217,498

Intangible assets, net, consists of customer relationships, dedicated acreage agreements, collaborative arrangements, noncompete agreements and trade names. 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 (in thousands):

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	March 31, 2017		
	Gross carrying amount	Accumulated amortization	Net carrying amount
Customer relationships	$133,503	$ (35,806)	$97,697
Customer contracts	95,594	(35,634)	59,960
Dedicated acreage	53,350	(4,882)	48,468
Collaborative arrangements	11,884	(778)	11,106
Noncompete agreements	3,423	(3,175)	248
Other	751	(215)	536
Total	$298,505	$ (80,490)	$218,015

	December 31, 2016		
	Gross carrying amount	Accumulated amortization	Net carrying amount
Customer relationships	$133,503	$ (31,471)	$102,032
Customer contracts	95,594	(33,414)	62,180
Dedicated acreage	53,350	(4,439)	48,911
Collaborative arrangements	11,884	(601)	11,283
Noncompete agreements	3,423	(3,086)	337
Other	751	(211)	540
Total	$298,505	$ (73,222)	$225,283

Amortization expense related to our intangible assets totaled $7.3 million and $5.2 million for the three months ended March 31, 2017 and 2016, respectively.

8. Investment in unconsolidated affiliates

The following table presents the activity in our investments in unconsolidated affiliates (in thousands):

	Delta House [1]		Emerald Transactions					
	FPS	OGL	Destin	Tri-States	Okeanos	Wilprise	MPOG	Total
Ownership % at March 31, 2017	20.1 %	20.1 %	49.7 %	16.7 %	66.7 %	25.3 %	66.7 %	
Balances at December 31, 2016	$64,483	$25,450	$110,882	$55,022	$27,059	$4,944	$4,148	$291,988
Earnings in unconsolidated affiliates	7,088	3,636	2,126	899	1,572	188	(107)	15,402
Distributions	(6,986)	(3,555)	(6,258)	(1,100)	(3,667)	(228)	(700)	(22,494)
Balances at March 31, 2017	$64,585	$25,531	$106,750	$54,821	$24,964	$4,904	$3,341	$284,896

[1] Represents direct and indirect ownership interests in Class A Units.

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The following tables present the summarized combined financial information for our equity investments (amounts represent 100% of investee financial information):

Balance Sheets:	March 31, 2017	December 31, 2016
Current assets	$87,406	$120,600
Non-current assets	1,353,629	1,387,675
Current liabilities	62,231	64,099
Non-current liabilities	$584,742	$623,650

	Three months ended March 31,	
Statements of Operations:	2017	2016
Revenue	$98,439	$65,542
Cost of sales and operating expenses	18,300	5,392
Gross profit	80,139	60,150
Income from continuing operations	58,595	55,548
Net income	$58,595	$55,548

The unconsolidated affiliates were determined to be variable interest entities due to disproportionate economic interests and decision making rights. In each case, we lack the power to direct the activities that most significantly impact the unconsolidated affiliate's economic performance. 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 condensed consolidated balance sheet at March 31, 2017. In each case, we are not obligated to absorb losses greater than our proportional ownership percentages indicated above. Our right to receive residual returns is not limited to any amount less than the ownership percentages indicated above.

9. Accrued Expenses and Other Current Liabilities

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

	March 31, 2017	December 31, 2016
Capital expenditures	$11,302	$ 14,499
Accrued interest	8,526	5,743
Convertible preferred unit distributions	6,707	7,103
Employee compensation	7,881	10,804
Current portion of asset retirement obligation	6,499	6,499
Legal accrual	5,150	—
Additional Blackwater acquisition consideration	5,000	5,000
Transaction costs	4,539	3,000
Royalties payable	3,597	3,926
Escrow settlement	3,135	—
Customer deposits	2,083	3,080
Taxes payable	2,800	1,688
Due to related parties	1,523	4,072
Gas imbalances payable	1,454	1,098
Deferred financing costs	—	2,743
Recoverable gas costs	393	1,126

Other	10,298	10,903
	$80,887	$ 81,284

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10. Asset Retirement Obligations

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations (collectively, referred to as "AROs") that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. Generally, the fair value of the liability is calculated using discounted cash flow techniques and based on internal estimates and assumptions related to (i) future retirement costs, (ii) future inflation rates and (iii) credit-adjusted risk-free interest rates. Significant increases or decreases in the assumptions would result in a significant change to the fair value measurement.

Certain assets related to our Offshore Pipelines Services segment have regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These AROs include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. These assets have been in existence for many years and with regular maintenance will continue to be in service for many years to come. It is not possible to predict when demand for these transmission services will cease, however, we do not believe that such demand will cease for the foreseeable future. The majority of the current portion of our AROs is related to the retirement of the Midla pipeline discussed in Note 16 - Commitments and Contingencies.

The following table presents activity in our asset retirement obligations for the three months ended March 31, 2017 (in thousands):

Non-current balance	$44,363
Current balance	6,499
Balances at December 31, 2016	$50,862
Expenditures	(41)
Accretion expense	487
Balances at March 31, 2017	$51,308
Less: current portion	6,499
Noncurrent asset retirement obligation	$44,809

We are required to establish security against potential obligations relating to the abandonment of certain transmission assets that may be imposed on the previous owner by applicable regulatory authorities. We have deposited $5.0 million with a third party to secure our performance on these potential obligations. These deposits are included in Restricted cash-long term in our condensed consolidated balance sheets as of March 31, 2017 and December 31, 2016.

11. Debt Obligations

Our outstanding debt consists of the following (in thousands):

	March 31, 2017	December 31, 2016
Revolving credit facility	$644,842	$888,250
8.5% Senior Notes, due 2021	300,000	300,000
3.77% Senior Notes, due 2031 (Non-Recourse)	60,000	60,000
Other debt	1,546	3,809
Total debt obligations	1,006,388	1,252,059
Unamortized debt issuance costs [1]	(10,228)	(11,036)
Total debt	996,160	1,241,023
Less: Current portion, including unamortized debt issuance costs	(3,223)	(5,485)
Long term debt	$992,937	$1,235,538

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

Credit Agreement

On March 8, 2017, we and our operating company, American Midstream, LLC, along with other of our subsidiaries entered into a Second Amended and Restated Credit Agreement with Bank of America N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders (the “Credit Agreement”) which increased our borrowing capacity from $750.0 million to $900.0 million and provided for an accordion feature that will permit,

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subject to the customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion. We can elect to have loans under our Credit Agreement bear interest either at a Eurodollar-based rate, plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (i) the Federal Funds Rate, plus 0.50%, (ii) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its “prime rate”, or (iii) the Eurodollar Rate plus 1.00%, plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan under the Credit Agreement.

The Second Amended and Restated 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 (except for the fiscal quarters ended March 31, 2017, and the subsequent two quarters, at which time the covenant is increased to 5.50 times adjusted consolidated EBITDA), 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. In addition to the financial covenants described above, the agreement also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events).

As of March 31, 2017, we had approximately $644.8 million of borrowings and $25.9 million of letters of credit outstanding under the Credit Agreement resulting in $670.7 million of available borrowing capacity.

As of March 31, 2017, our consolidated total leverage ratio was 4.64 and our interest coverage ratio was 6.19, which were both in compliance with the related requirements of our Credit Agreement. Our ability to maintain compliance with the leverage and interest coverage ratios included in the Credit Agreement may be subject to, among other things, the timing and success of initiatives we are pursuing, which may include expansion capital projects, acquisitions or drop down transactions, as well as the associated financing for such initiatives.

The carrying value of amounts outstanding under our Credit Agreement approximates the related fair value, as interest charges vary with market rates conditions.

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 acquisition, the $199.5 million outstanding balance of the JPE Revolver was paid off in full and terminated.

For the three months ended March 31, 2017 and 2016, the weighted average interest rate on borrowings under our Credit Agreement and the JPE revolver was approximately 4.44% and 4.07%, respectively.

8.50% Senior Unsecured Notes

On December 28, 2016, we and American Midstream Finance Corporation, our wholly-owned subsidiary (the “Co-Issuer” and together with the Partnership, the “Issuers”), completed the issuance and sale of the 8.50% Senior Notes. The 8.50% Senior Notes are jointly and severally guaranteed by our existing direct and indirect wholly owned subsidiaries (other than the Co-Issuer) and certain of our future subsidiaries (the “Guarantors”). The 8.50% Senior Notes rank equal in right of payment with all existing and future senior indebtedness of the Issuers, and senior in right of payment to any future subordinated indebtedness of the Issuers. The 8.50% Senior Notes were issued at par and provided approximately $294.0 million in proceeds, after deducting the initial purchasers' discount of $6.0 million. This amount was deposited into escrow pending completion of the JPE Acquisition and was included in Restricted cash-long term on our condensed consolidated balance sheet as of December 31, 2016. We 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 Acquisition and the satisfaction of other related conditions the restricted cash was released from escrow on March 8, 2017 and used to repay and terminate JPE’s revolving credit facility and reduce borrowings under the Partnership’s Amended and Restated Credit Agreement then in effect.

As of March 31, 2017, the fair value of the 8.50% Senior Notes was $305.6 million. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

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3.77% Senior Secured Notes

On September 30, 2016, Midla Financing, LLC ("Midla Financing"), American Midstream (Midla) LLC ("Midla"), and Mid Louisiana Gas Transmission LLC ("MLGT and together with Midla, the "Note Guarantors") entered into a Note Purchase and Guaranty Agreement with certain institutional investors (the "Purchasers") whereby Midla Financing issued $60.0 million in aggregate principal amount of 3.77% Senior Notes (non-recourse) due June 30, 2031.

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. Many of these provisions apply not only to Midla Financing and the Note Guarantors, but also to American Midstream Midla Financing Holdings, LLC ("Midla Holdings"), a wholly owned subsidiary of the Partnership and the sole member of Midla Financing. Among other things, 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 (a) until June 30, 2017, (b) unless the debt service coverage ratio is not less than, and is not projected for the following 12 calendar months to be less than, 1.20:1.00, and (c) unless certain other requirements are met.

As of March 31, 2017, the fair value of the 3.77% Senior Notes was $54.6 million. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

12. Convertible Preferred Units

Our convertible preferred units consist of the following (in thousands):

	Series A		Series C		Series D	
	Units	$	Units	$	Units	$
December 31, 2016	10,107	$181,386	8,792	$118,229	2,333	$34,475
Paid in kind unit distributions	159	2,181	—	—	—	—
March 31, 2017	10,266	$183,567	8,792	$118,229	2,333	$34,475

Affiliates of our General Partner hold and participate in quarterly distributions on our convertible preferred units, with such distributions being made in cash, paid-in-kind units or a combination thereof, at the election of the Board of Directors of our General Partner, although quarterly distribution on our Series D Units will only be paid in cash. The convertible preferred unitholders have the right to receive cumulative distributions in the same priority and prior to any other distributions made in respect of any other partnership interests.

To the extent that any portion of a quarterly distribution on our convertible preferred units to be paid in cash exceeds the amount of cash available for such distribution, the amount of cash available will be paid to our convertible preferred unitholders on a pro rata basis while the difference between the distribution and the available cash will become arrearages and accrue interest until paid.

Series A-1 Convertible Preferred Units

On April 15, 2013, we, 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, subject to customary anti-dilutive adjustments, at the option of the unitholders on or any time after January 1, 2014. As of March 31, 2017, the conversion price is $15.87 and the conversion ratio is 1 to 1.1027.

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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 we issued, in separate private placements, newly-designated Series A-2 Units (the “Series A-2 Units”) representing limited partnership interests in the Partnership. As a result, the Partnership issued a total of 2,571,430 Series A-2 Units for approximately $45.0 million in aggregate proceeds during the year ended December 31, 2015. The Series A-2 Units will participate in distributions of the Partnership along with common units in a manner identical to the existing Series A-1 Units (together with the Series A-2 Units, the "Series A Units"), with such distributions being made in cash or with paid-in-kind Series A Units at the election of the Board of Directors of our General Partner.

On July 27, 2015, we amended our Partnership Agreement to grant us the right (the “Call Right”) to require the holders of the Series A-2 Units to sell, assign and transfer all or a portion of the then outstanding Series A-2 Units to us for a purchase price of $17.50 per Series A-2 Unit (subject to appropriate adjustment for any equity distribution, subdivision or combination of equity interests in the Partnership). We may exercise the Call Right at any time, in connection with our or our affiliate’s acquisition of assets or equity from ArcLight Energy Partners Fund V, L.P., or one of its affiliates, for a purchase price in excess of $100 million. We may not exercise the Call Right with respect to any Series A-2 Units that a holder has elected to convert into common units on or prior to the date we have provided notice of our intent to exercise the Call Right, and we may also not exercise the Call Right if doing so would result in a default under any of our or our affiliates’ financing agreements or obligations. As of March 31, 2017, the conversion price is $15.87 and the conversion ratio is 1 to 1.1027.

Third Amendment to Partnership Agreement

The Partnership also executed Amendment No. 3 to our Fifth Amended and Restated Partnership Agreement (as amended, the “Partnership Agreement”), which amends the distribution payment terms of the Partnership’s outstanding Series A Preferred Units to provide for the payment of a number of Series A payment-in-kind (“PIK”) preferred units for the quarter (the “Series A Preferred Quarterly Distribution”) in which the JPE Acquisition is consummated (which is the quarter ended March 31, 2017) and each quarter thereafter equal to the quotient of (i) the greater of (a) $0.4125 and (b) the "Series A Distribution Amount", as such term is defined in the Partnership Agreement, divided by (ii) the Series A Adjusted Issue Price, as such term is defined in the Partnership Agreement. However, in our General Partner’s discretion, which determination shall be made prior to the record date for the relevant quarter, the Series A Preferred Quarterly Distribution may be paid as a combination (x) an amount in cash up to the greater of (1) $0.4125 and (2) the Series A Distribution Amount, and (y) a number of Series A Preferred Units equal to the quotient of (a) the remainder of (i) the greater of (I) $0.4125 and (II) the Series A Distribution Amount less (ii) the amount of cash paid pursuant to clause (x), divided by (b) the Series A Adjusted Issue Price. This calculation results in a reduced Series A Preferred Quarterly Distribution, which was previously calculated under the Partnership Agreement using $0.50 in place of $0.4125 in the preceding calculations.

Series C Convertible Preferred Units

On April 25, 2016, we issued 8,571,429 Series C Units to an ArcLight affiliate in connection with the purchase of membership interests in certain midstream entities.

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 we issue, sell or grant 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 March 31, 2017, the conversion price is $13.95 and the conversion ratio is 1 to 1.0036.

In connection with the issuance of the Series C Units, we issued the holders a warrant to purchase up to 800,000 common units at an exercise price of $7.25 per common unit (the "Series C Warrant"). The Series C Warrant is subject to standard anti-dilution adjustments and is exercisable for a period of seven years.

The fair value of the Series C Warrant was determined using a market approach that utilized significant inputs which are not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. The estimated fair value of $4.41 per warrant unit was determined using a Black-Scholes model and the following significant assumptions: i) a dividend yield of 18%, ii) common unit volatility of 42% and iii) the seven-year term of the warrant to arrive at an aggregate fair value of $4.5 million.

Series D Convertible Preferred Units

On October 31, 2016, we issued 2,333,333 shares of our 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 during the third quarter 2016. The related agreement provides that if any of the Series D Units remain outstanding on June 30, 2017, we will issue the holder of the Series D Units a warrant (the "Series D Warrant") to purchase 700,000 common units representing limited partnership interests with an exercise price of $22.00 per common unit. The fair value of the conditional Series D Warrant at the time of issuance was immaterial.

The Series D Units are entitled to quarterly distributions payable in arrears equal to the greater of $0.4125 and the cash distribution that the Series D Units would have received if they had been converted to common units immediately prior to the beginning of the quarter. The Series D Units also have separate class voting rights on any matter, including a merger, consolidation or business combination, that adversely affects, amends or modifies any of the rights, preferences, privileges or terms of the Series D Units. The Series D Units are convertible in whole or in part into common units at the election of the holder of the Series D Unit at any time after June 30, 2017. As of the date of issuance, the conversion rate for each Series D Unit was one-to-one (the "Conversion Rate"). As of March 31, 2017, the conversion price is $15.00 and the conversion ratio is 1 to 1.

13. Partners' Capital

Outstanding Units

The following table presents unit activity (in thousands):

	General Partner Interest	Limited Partner Interest
Balances at December 31, 2016	680	51,351
LTIP vesting	—	259
Issuance of common units	—	21
Issuance of GP units	8	—
Balances at March 31, 2017	688	51,631

Our capital accounts are comprised of approximately 0.9% notional General Partner interests and 99.1% limited partner interests as of March 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 capital account. As such, allocation of losses and distributions, including distributions for previous transactions between entities under common control, has resulted in a deficit to the General Partner's capital account included in our condensed consolidated balance sheets.

General Partner Units

In order to maintain its ownership percentage, we received proceeds of $0.1 million from our General Partner as consideration for the issuance of 8,665 additional notional General Partner units for the three months ended March 31, 2017. For the three months ended March 31, 2016, we received proceeds of $0.1 million for the issuance of 6,225 additional notional General Partner units.

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Distributions

We made the following distributions (in thousands):

	Three months ended March 31,	
	2017	2016
Series A Units		
Cash Paid	$2,527	$ —
Accrued	4,296	4,471
Paid-in-kind units	2,733	4,380
Series C Units		
Cash Paid	3,627	—
Accrued	3,627	—
Series D Units		
Cash Paid	962	—
Accrued	962	—
Limited Partner Units		
Cash Paid	24,915	27,000
General Partner Units		
Cash Paid	167	2,028
Summary		
Cash Paid	32,198	29,028
Accrued	8,885	4,471
Paid-in-kind units	2,733	4,380

The fair value of the paid-in-kind distributions was determined using the market and income approaches, requiring significant inputs which are not observable in the market and thus represent a Level 3 measurement as defined by ASC 820. Under the income approach, the fair value estimates for all periods presented were based on i) present value of estimated future contracted distributions, ii) option values ranging from $0.02 per unit to $9.68 per unit using a Black-Scholes model, iii) assumed discount rates ranging from 5.57% to 10.0% and iv) assumed growth rates of 1.0%.

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14. Net Income (Loss) per Limited Partner Unit

Net income (loss) is allocated to the General Partner and the limited partners in accordance with their respective ownership percentages, after giving effect to distributions on our convertible preferred units and General Partner units, including incentive distribution rights. Unvested unit-based compensation awards that contain non-forfeitable rights to distributions (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net limited partners' net income (loss) per common unit. Basic and diluted limited partners' net income (loss) per common unit is calculated by dividing limited partners' interest in net income (loss) by the weighted average number of outstanding limited partner units during the period.

As discussed in Note 1, the JPE Acquisition was a combination between entities under common control. As a result, prior periods were retrospectively adjusted to furnish comparative information. Accordingly, the prior period earnings combining both entities were allocated among our General Partners and common unitholders assuming JPE units were converted into our common units in the comparative historical periods.

The calculation of basic and diluted limited partners' net income (loss) per common unit is summarized below (in thousands, except per unit amounts):

	Three months ended March 31,	
	2017	2016
Net (loss) from continuing operations	$(28,881)	$(10,064)
Less: Net income (loss) attributable to noncontrolling interests	1,303	(3)
Net loss from continuing operations attributable to the Partnership	(30,184)	(10,061)
Less:		
Distributions on Series A Units	4,296	4,471
Distributions on Series C Units	3,627	—
Distributions on Series D Units	962	—
General partner's distribution	200	2,028
General partner's share in undistributed loss	(560)	(418)
Net loss from continuing operations attributable to Limited Partners	(38,709)	(16,142)
Net loss from discontinued operations attributable to Limited Partners	—	(539)
Net loss attributable to Limited Partners	$(38,709)	$(16,681)
Weighted average number of common units used in computation of Limited Partners' net loss per common unit - basic and diluted	51,451	50,925
Limited Partners' net loss from continuing operations per unit	$(0.75)	$(0.32)
Limited Partners' net loss from discontinued operations per unit	—	(0.01)
Limited Partners' net loss per common unit (1)	$(0.75)	$(0.33)

(1) Potential common unit equivalents are antidilutive for all periods and, as a result, have been excluded from the determination of diluted limited partners' net income (loss) per common unit.

15. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 19, 2015, the Board of Directors of our General Partner approved the Third Amended and

Restated Long-Term Incentive Plan to, among other things, increase the number of common units authorized for issuance by 6,000,000 common units. On February 11, 2016, the unitholders approved the Third Amended and Restated Long-Term Incentive Plan (as amended and as currently in effect as of the date hereof, the “LTIP”). On March 9, 2017, additional 312,716 common units were registered to be issued in relation to the converted JPE phantom units.

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All such equity-based awards issued under the LTIP consist of phantom units, distribution equivalent rights (“DERs”) or option grants. DERs and options have been granted on a limited basis. Future awards may be granted at the discretion of the Compensation Committee and subject to approval by the Board of Directors of our General Partner.

Phantom Unit Awards. Ownership in the phantom unit awards is subject to forfeiture until the vesting date. The LTIP is administered by the Compensation Committee of the Board of Directors of our General Partner, which at its discretion, may elect to settle such vested phantom units with a number of common units equivalent to the fair market value at the date of vesting in lieu of cash. Although our General Partner has the option to settle in cash upon the vesting of phantom units, our General Partner has not historically settled these awards in cash. Under the LTIP, phantom units typically vest over 3-4 years 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 based on the extent to which our Series A 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 three months ended March 31, 2017:

	Units	Weighted-Average Grant Date Fair Value Per Unit
Outstanding units at December 31, 2016	1,558,835	$ 6.98
Granted	2,000	11.20
Forfeited	(964)	30.14
Vested	(319,572)	7.41
Outstanding units at March 31, 2017	1,240,299	$ 6.86

The fair value of our phantom units, which are subject to equity classification, is based on the fair value of our common units at the grant date. Compensation expense related to these awards for the three months ended March 31, 2017 and 2016 was $4.0 million and $1.6 million respectively, and is included in Corporate expenses and Direct operating expenses in our unaudited condensed consolidated statements of operations and Equity compensation expense in our unaudited condensed consolidated statements of changes in partners’ capital and noncontrolling interests.

The total fair value of units at the time of vesting was $5.0 million and $0.9 million for the three months ended March 31, 2017 and 2016, respectively.

16. Commitments and Contingencies

Legal proceedings

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

Environmental matters

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to our operations, and we could, at times, be subject to environmental cleanup and enforcement actions. We attempt to manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment.

Regulatory matters

On October 8, 2014, American Midstream (Midla), LLC ("Midla") reached an agreement in principle with its customers regarding the interstate pipeline that traverses Louisiana and Mississippi in order to provide continued service to its customers while addressing safety concerns with the existing pipeline.

On April 16, 2015, FERC approved the stipulation and agreement (the “Midla Agreement”) relating to the October 8, 2014 regulatory matter allowing Midla to retire the existing 1920’s pipeline and replace it with the Midla-Natchez Line to serve existing residential, commercial, and industrial customers. Under the Midla Agreement, customers not served by the new Midla-Natchez Line will be connected to other interstate or intrastate pipelines, other gas distribution systems, or offered conversion to propane service. On June 29, 2015, we filed with FERC for authorization to construct the Midla-Natchez pipeline, which was approved on December 17, 2015. Construction commenced in the second quarter of 2016, and services commenced on March 31, 2017. Under the Midla Agreement, Midla executed long-term agreements seeking to recover its investment in the Midla-Natchez Line.

Merger related costs

As part of the JPE Acquisition, 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 render service through their respective termination date. We have estimated the fair value of the obligation to be approximately $3.4 million, which has been recorded as of March 31, 2017.

17. Related Party Transactions

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. During the third quarter of 2016, we determined that it was probable the operating targets would be met in early 2017 and recorded a $5.0 million accrued distribution to the ArcLight affiliate which is included in Accrued expense and other current liabilities in the accompanying condensed consolidated financial statements as of March 31, 2017.

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 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 JPE Acquisition closing during the first quarter of 2017, our General Partner agreed to provide quarterly financial support up to a maximum of $25 million . The financial support will continue for eight (8) consecutive quarters following the closing of the merger, or if earlier, until $25 million in support has been provided. The General Partner would also reimburse the Partnership for certain expenses it incurs in connection with the post closing transition for one year. We have not currently utilized any of the financial support mentioned above.

Separate from the financial support described above, our General Partner agreed to absorb $9.6 million corporate overhead expenses incurred by us in the first quarter of 2017 and not pass such expense through to us.

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 the condensed consolidated statements of operations by $0.3 million for each of the three months ended March 31, 2017 and March 31, 2016. As of March 31, 2017, we had a receivable balance due from Republic of $1.4 million, which is included in Receivables from related parties in the condensed consolidated balance sheet.

As of March 31, 2017 and December 31, 2016, we had $1.3 million and $3.9 million, respectively, due to our General Partner, which has been recorded in Accrued expenses and other current liabilities and relates primarily to compensation. This payable is generally settled on a quarterly basis related to the foregoing transactions.

On November 1, 2016, we became operator of the Destin and Okeanos pipelines and entered into an operating and administrative management agreements under which the affiliates pay a monthly fee for general and administrative services provided by us. In addition, the affiliates reimburse us for certain transition related expenses. For the three months ended March 31, 2017, we recognized $0.6 million of management fee income.

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American Panther, LLC ("American Panther") is a 60%-owned subsidiary of us which is consolidated for financial reporting purposes. Pursuant to a related agreement which began in the second quarter of 2016, an affiliate of the non-controlling interest holder provides services to American Panther in exchange for related fees, which in 2016 totaled $0.8 million of Direct operating expenses and $0.4 million of Corporate expenses in the unaudited condensed consolidated statement of operations. During the three months ended March 31, 2017, we provided services for related fees which totaled $0.3 million of Direct operating expenses and $0.1 million of Corporate expenses in the unaudited condensed consolidated statement of operations.

We enter into purchases and sales of natural gas and crude oil with a company whose chief financial officer is the brother of one of our executive officers. During the three months ended March 31, 2017, and 2016, we recognized revenue of $0.7 million, and $0.9 million, respectively, while purchases from this company totaled $1.4 million, and $1.0 million, respectively.

JP Energy Development ("JP Development"), an affiliate owned by Arclight, 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, JPE incurred pipeline tariff fees of $0.4 million for the three months ended March 31, 2016, which have been included in net loss from discontinued operations in the condensed consolidated statements of operations. We combined the cash flows from the MidContinent Business with the cash flows from continuing operations for all periods presented in the consolidated statements of cash flows. As of December 31, 2015, we had a net receivable from JP Development of $7.9 million, primarily as the result of the prepayments made in 2014 for the crude oil pipeline transportation services to be provided by JP Development. We recovered these amounts in full on February 1, 2016.

On February 1, 2016, JPE 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, JPE's general partner agreed to absorb 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 $4.0 million and $2.5 million for the three months ended March 31, 2017 and 2016, respectively. JPE's general partner agreed to absorb $1.5 million of such corporate overhead expenses in the three months ended March 31, 2016.

18. Supplemental Cash Flow Information

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

	Three months ended March 31, 2017	2016
Supplemental non-cash information		
Increase (decrease) in accrued property, plant and equipment purchases	$(1,371)	$1,876
Contributions from General Partner	4,000	2,500
Accrued distributions on convertible preferred units	8,885	4,471
Paid-in-kind distributions on convertible preferred units	2,733	4,380
Cancellation of escrow units	—	6,817

19. Reportable Segments

During the first quarter of 2017, as a result of the acquisition of JPE described in Note 1, we realigned the composition of our reportable segments. Accordingly, we have restated the items of segment information for the three months ended March 31, 2016 to reflect this new segment adjustment.

Our operations are located in the United States and are organized into six reportable segments: 1) Gas Gathering and Processing Services, 2) Liquid Pipelines and Services, 3) Natural Gas Transportation Services, 4) Offshore Pipeline and Services, 5) Terminalling Services, and 6) Propane Marketing Services.

- Gas Gathering and Processing Services. Our Gas Gathering and Processing Services segment provides "wellhead-to-market" services to producers of natural gas and natural gas liquids, 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.

- Propane Marketing Services. Our Propane Marketing Services segment gathers, transports and sells natural gas liquids (NGLs). This is accomplished through cylinder tank exchange, sales through retail, commercial and wholesale distribution and through a fleet of trucks operating in the Eagle Ford and Permian basin areas.

These segments are monitored separately by our chief operating decision maker ("CODM") for performance and are consistent with our internal financial reporting. The CODM periodically reviews segment gross margin information for each segment to make business decisions. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations.

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, Terminalling Services and
Propane Marketing Services segments.

We define segment gross margin in our Gas Gathering and Processing Services segment as total revenue plus unconsolidated affiliate earnings less unrealized gains or plus unrealized losses on commodity derivatives, construction and operating management agreement income and the cost of natural gas, crude oil and NGLs and condensate purchased.

We define segment gross margin in our Liquid Pipelines and Services segment as total revenue plus unconsolidated affiliate earnings less unrealized gains or plus unrealized losses on commodity derivatives and the cost of crude oil purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

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

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

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

We define segment gross margin in our Propane Marketing Services segment as total revenue less purchases of natural gas, NGLs and condensate excluding non-cash charges such as non-cash unrealized gains or plus unrealized losses on commodity derivatives.

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A reconciliation from Segment Gross Margin to Net Income attributable to the Partnership for the periods ended March 31, 2017 and March 31, 2016 is below (in thousands):

	Three months ended March 31, 2017	2016
Reconciliation of Segment Gross Margin to Net income (loss) attributable to the Partnership:		
Gas Gathering and Processing Services segment gross margin	$11,251	$11,619
Liquid Pipelines and Services segment gross margin	6,470	5,850
Natural Gas Transportation Services segment gross margin	6,119	5,563
Offshore Pipelines and Services segment gross margin	25,802	13,265
Terminalling Services segment gross margin (1)	11,160	9,443
Propane Marketing Services segment gross margin	19,302	28,305
Total Segment Gross Margin	80,104	74,045
Less:		
Other direct operating expenses (1)	27,015	27,966
Total Operating Margin	53,089	46,079
Plus:		
Loss on commodity derivatives, net	(257)	(238)
Less:		
Corporate expenses	32,844	21,101
Depreciation, amortization and accretion expense	29,351	25,041
(Gain) loss on sale of assets, net	(228)	1,122
Interest expense	17,966	8,302
Other income	(14)	(31)
Other, net	671	(365)
Income tax expense	1,123	735
Loss from discontinued operations, net of tax	—	539
Net income (loss) attributable to noncontrolling interest	1,303	(3)
Net income (loss) attributable to the Partnership	$(30,184)	$(10,600)

(1) Other direct operating expenses include Gas Gathering and Processing segment direct operating expenses of $8.1 million and $8.5 million, respectively, Liquid Pipelines and Services segment direct operating expenses of $2.1 million and $2.5 million, respectively, Natural Gas Transportation Services segment direct operating expenses of $1.2 million and $1.2 million, respectively, Offshore Pipelines and Services segment direct operating expenses of $2.6 million and $2.3 million, respectively, Propane Marketing Services segment direct operating expenses of $13.1 million and $13.5 million, respectively, for the three months ended March 31, 2017 and 2016. Direct operating expenses related to our Terminalling Services segment of $3.1 million and $2.6 million for the three months ended March 31, 2017 and 2016, respectively, are included within the calculation of Terminalling Services segment gross margin.

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The following tables set forth our segment information for the three months ended March 31, 2017 and 2016 (in thousands):

	Three months ended March 31, 2017						
	Gas Gathering and Processing Services	Liquid Pipelines and Services	Natural Gas Transportation Services	Offshore Pipelines and Services	Terminalling Services	Propane Marketing Services	Total
Revenue	$34,407	$82,039	$12,438	$14,831	$18,626	$37,548	$199,889
Gain (loss) on commodity derivatives, net	(7)	372	—	—	—	(622)	(257)
Total revenue	34,400	82,411	12,438	14,831	18,626	36,926	199,632
Earnings in unconsolidated affiliates	—	1,088	—	14,314	—	—	15,402
Operating expenses:							
Cost of Sales	23,187	77,077	6,260	3,343	4,393	18,525	132,785
Direct operating expenses	8,065	2,074	1,235	2,579	3,073	13,062	30,088
Corporate expenses							32,844
Depreciation, amortization and accretion expense							29,351
Gain on sale of assets, net							(228)
Total operating expenses							224,840
Interest expense							17,966
Other (income) expense							(14)
Loss from continuing operations before taxes							(27,758)
Income tax expense							1,123
Net loss							(28,881)
Less: Net income attributable to non-controlling interests							1,303
Net loss attributable to the Partnership							$(30,184)
Segment gross margin	$11,251	$6,470	$6,119	$25,802	$11,160	$19,302	

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	Three months ended March 31, 2016						
	Gas Gathering and Processing Services	Liquid Pipelines and Services	Natural Gas Transportation Services	Offshore Pipelines and Services	Terminalling Services	Propane Marketing Services	Total
Revenue	$23,295	$44,515	$ 9,795	$7,003	$ 14,393	$ 44,613	$143,614
Gain (loss) on commodity derivatives, net	(103)	(233)	—	—	(175)	273	(238)
Total revenue	23,192	44,282	9,795	7,003	14,218	44,886	143,376
Earnings in unconsolidated affiliates	—	—	—	7,343	—	—	7,343
Operating expenses:							
Cost of Sales	11,707	38,654	4,224	1,081	2,205	16,067	73,938
Direct operating expenses	8,548	2,467	1,227	2,253	2,609	13,471	30,575
Corporate expenses							21,101
Depreciation, amortization and accretion expense							25,041
Loss on sale of assets, net							1,122
Total operating expenses							151,777
Interest expense							8,302
Other (income) expense							(31)
Loss from continuing operations before taxes							(9,329)
Income tax expense							735
Income (loss from continuing operation							(10,064)
Loss from discontinued operations, net of tax							539
Net loss							(10,603)
Less: Net loss attributable to non-controlling interests							(3)
Net loss attributable to the Partnership							$(10,600)
Segment gross margin	$11,619	$5,850	$ 5,563	$13,265	$9,443	$ 28,305	

A reconciliation of total assets by segment to the amounts included in the condensed consolidated balance sheets follows:

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	March 31, 2017	December 31, 2016
Segment assets:		
Gas Gathering and Processing Services	$390,334	$532,009
Liquid Pipelines and Services	447,121	422,636
Offshore Pipelines and Services	365,507	385,893
Natural Gas Transportation Services	176,740	221,604
Terminalling Services	277,632	299,534
Propane Marketing Services	134,604	140,864
Other (1)	254,305	346,781
Total assets	$2,046,243	$2,349,321

(1) Other assets not allocable to segments consist of corporate leasehold improvements and other assets.

20. Subsequent Events

Distribution

On April 25, 2017, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit for the quarter ended March 31, 2017, or $1.65 per common unit on an annualized basis. The distribution is expected to be paid on May 12, 2017, to unitholders of record as of the close of business on May 5, 2017.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following management's discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited condensed consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report on Form 10-Q ("Quarterly Report") and the audited consolidated financial statements and notes thereto and management's discussion and analysis of financial condition and results of operations as of and for the year ended December 31, 2016 included in our Annual Report on Form 10-K ("Annual Report") that was filed with the Securities and Exchange Commission ("SEC") on March 28, 2017. 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." In addition, please read the Annual Report on Form 10-K for the year ended December 31, 2016 filed by JP Energy Partners, LP, which is not a part of this Quarterly Report or our Annual Report. We acquired JP Energy Partners, LP on March 8, 2017.

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". You can typically identify forward-looking statements by the use of forward-looking 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. Examples of these risks and uncertainties, many of which are beyond our control, include, but are not limited to, the following:

- our ability to integrate with JP Energy Partners LP (“JPE”) successfully;
- our ability to generate sufficient cash from operations to pay distributions to unitholders;
- our ability to maintain compliance with financial covenants and ratios in our Credit Facility (as defined herein);

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- our ability to timely and successfully identify, consummate and integrate our current and future acquisitions and complete strategic dispositions, including the realization of all anticipated benefits of any such transaction, which otherwise could negatively impact our future financial performance;
- the timing and extent of changes in natural gas, crude oil, NGLs, refined products and other commodity prices, interest rates and demand for our services;
- our ability to access capital to fund growth, including new and amended credit facilities and access to the debt and equity markets, which will depend on general market conditions;
- severe weather and other natural phenomena, including their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- the level of creditworthiness of counterparties to transactions;
- the level and success of natural gas and crude oil drilling around our assets and our success in connecting natural gas and crude oil supplies to our gathering and processing systems;
- the volumes of natural gas and crude oil that we gather, process, transport and store, the throughput volume at our refined products terminals and our NGL sales volumes;
- the fees that we receive for the natural gas, crude oil, refined products and NGL volumes we handle;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- changes in laws and regulations, particularly with regard to taxes, safety, regulation of over-the-counter derivatives market and entities, and protection of the environment;
- our failure or our counterparties' failure to perform on obligations under commodity derivative and financial derivative contracts;
- the performance of certain of our current and future projects and unconsolidated affiliates that we do not control;
- the demand for natural gas, crude oil, NGL and refined products by the petrochemical, refining or other industries;
- our dependence on a relatively small number of customers for a significant portion of our gross margin;
- general economic, market and business conditions, including industry changes and the impact of consolidations and changes in competition;
- our ability to renew our gathering, processing, transportation and terminal contracts;
- our ability to successfully balance our purchases and sales of natural gas;
- leaks or releases of hydrocarbons into the environment that result in significant costs and liabilities;
- the adequacy of insurance to cover our losses;
- our ability to grow through contributions from affiliates, acquisitions or internal growth projects;
- our management's history and experience with certain aspects of our business and our ability to hire as well as retain qualified personnel to execute our business strategy;
- the cost and effectiveness of our remediation efforts with respect to the material weakness discussed in "Part II. Item 9A. Controls and Procedures";
- volatility in the price of our common units;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- the amount of collateral required to be posted from time to time in our transactions.

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

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 six financial reporting segments, (i) gas gathering and processing services, (ii) liquids pipelines and services, (iii) natural gas transportation services, (iv) offshore pipelines and services , (v) terminalling services and (vi) propane marketing 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; storing specialty chemical products; and distributing and selling propane and refined products.

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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, and (iv) offshore in the Gulf of Mexico. Our liquids 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, our Propane Marketing Services assets are located in 46 states in the U.S. as well we operate a fleet of NGL gathering and transportation trucks in the Eagle Ford shale and the Permian Basin.

We own or have ownership interests in more than 3,800 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 16 gathering systems, six 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 80 MMBbl/d of crude oil and 200 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 97 transportation trucks.

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

Recent Developments

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. 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.

Financial Highlights

Financial highlights for the three months ended March 31, 2017, include the following:

- Net loss attributable to the Partnership increased to $30.2 million, primarily due to higher operating costs partially offset by an increase in total revenues and earnings from unconsolidated affiliates;

- Earnings in unconsolidated affiliates was $15.4 million, an increase of $8.1 million as compared to the same period in 2016, primarily due to the additional Delta House investments in Q2 and Q4 2016 and our Emerald Transactions;

- Segment gross margin amounted to $80.1 million, or an increase of $6.1 million as compared to the same period in 2016, primarily due higher segment gross margin in our offshore segment;

- Adjusted EBITDA increased to $46.7 million, or an increase of 29.0% as compared to the same period in 2016, primarily due to distributions from our investments in Delta House and the entities underlying the Emerald Transactions; and

- We distributed $24.9 million to our common unitholders, or $0.4125 per common unit.

Operational highlights for the three months ended March 31, 2017, include the following:

- Contracted capacity for our Terminals segment averaged 5,299,667 Bbls, representing a 17.3% increase compared to the same period in 2016;

- Average condensate production totaled 80.9 Mgal/d, representing a 10.2 Mgal/d increase compared to the same period in 2016;

- Average gross NGL production totaled 297.0 Mgal/d, representing a 21.7 Mgal/d increase compared to the same period in 2016;

- Throughput volumes attributable to the Natural Gas Transportation Services and Offshore Pipelines and Services segments totaled 794 MMcf/d, representing a 115 MMcf/d decrease compared to the same period in 2016;

- Throughput volumes attributable to the Liquid Pipelines and Services Segment totaled 34,638 Bbl/d, representing a 1,671 Bbl/d increase compared to the same period in 2016;

- NGL and refined product sales attributable to our Propane Marketing Services Segment totaled 202 Mgal/d, representing a decrease of 35 Mgal/d compared to the same period in 2016, mainly due to warmer than normal temperatures during the winter; and

- The percentage of gross margin generated from fee based, fixed margin, firm and interruptible transportation contracts and firm storage contracts (excluding propane) was 90.2% representing a decrease of 3.3% as compared to the same period in 2016.

JPE Acquisition

On March 8, 2017, we completed the acquisition of JPE, an entity controlled by affiliates of ArcLight Capital Partners, LLC ("ArcLight"), in a unit-for-unit merger (the “JPE Acquisition”).” 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 common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates.

As both we and JPE were controlled by ArcLight affiliates, the acquisition represents a transaction among entities under common control and has been accounted for as a common control transaction. Although we are the legal acquirer, JPE is considered to the acquirer for accounting purposes as ArcLight obtained control of JPE prior to it obtaining control of the Partnership on April 15, 2013. As a result, JPE will record the acquisition of the Partnership at ArcLight’s historical cost basis.

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

Third Amendment to Partnership Agreement

On March 8, 2017, we also executed Amendment No. 3 to our Fifth Amended and Restated Partnership Agreement (as amended, the “Partnership Agreement”), which amends the distribution payment terms of our outstanding Series A Preferred Units to provide for the payment of a number of Series A payment-in-kind (“PIK”) preferred units for the quarter (the “Series A Preferred Quarterly Distribution”) in which the JPE Acquisition is consummated (which is the quarter ended March 31, 2017) and each quarter thereafter equal to the quotient of (i) the greater of (a) $0.4125 and (b) the "Series A Distribution Amount", as such term is defined in the Partnership Agreement, divided by (ii) the “Series A Adjusted Issue Price,” as such term is defined in the Partnership Agreement. However, in our General Partner’s discretion, which determination shall be made prior to the record date for the relevant quarter, the Series A Preferred Quarterly Distribution may be paid as a combination of (x) an amount in cash up to the greater of (1) $0.4125 and (2) the Series A Distribution Amount, and (y) a number of Series A Preferred Units equal to the quotient of (a) the remainder of (i) the greater of (I) $0.4125 and (II) the Series A Distribution Amount less (ii) the amount of cash paid pursuant to clause (x), divided by (b) the Series A Adjusted Issue Price. This calculation results in a reduced Series A Preferred Quarterly Distribution, which was previously calculated under the Partnership Agreement using $0.50 in place of $0.4125 in the preceding calculations.

Second Amended and Restated Credit Agreement

On March 8, 2017, we and American Midstream, LLC, along with other of our subsidiaries (collectively, the “Borrowers”) entered into a Second Amended and Restated Credit Agreement with Bank of America, N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders (the “Second Amended Credit Agreement”). By entering into the Second Amended Credit Agreement, we amended our existing credit facility to increase our borrowing capacity thereunder from $750 million to $900 million and to provide for an accordion feature that will permit, subject to the customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion. The $900 million in lending commitments under the Second Amended Credit Agreement includes a $30 million sublimit for borrowings by the Blackwater Borrower and a $100 million sublimit for standby letters of credit, which was increased in this Second Amended Credit Agreement from $50 million. The Second Amended Credit Agreement matures on September 5, 2019. The Second Amended Credit Agreement facilitates the joinder to the credit facility of certain surviving entities from the JPE Acquisition (the "JPE

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Entities") and adjusts certain covenants, representations and warranties under the credit facility to support the JPE Entities. All obligations under the Second Amended Credit Agreement and the guarantees of those obligations are secured, subject to certain exceptions, by a first-priority lien on and security interest in substantially all of the Borrowers' assets and the assets of all, subject to certain exceptions, existing and future subsidiaries and all of the capital stock of the Partnership's existing and future subsidiaries.

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

8.50% Senior Unsecured Notes

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

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

Commodity Prices

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $54.45 per barrel to a low of $45.52 per barrel from January 1, 2017 through May 8, 2017. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.71 per MMBtu to a low of $2.44 per MMBtu from January 1, 2017 through May 8, 2017.

Fluctuations in energy prices can greatly affect the development of new crude oil and natural gas reserves. Further declines in commodity prices of crude oil and natural gas could have a negative impact on exploration, development and production activity, and, if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to continued or further 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. If commodity prices continue to remain depressed as they were in 2015 and in 2016, this could lead to reduced profitability and may impact our liquidity and compliance with financial covenants and ratios under our Credit Agreement, which include a maximum total leverage ratio which is measured on a quarterly basis. Reduced profitability could adversely affect our operations, our ability to pay distributions to our unitholders, and may result in future impairments of our long-lived assets, goodwill, and intangible assets.

Capital Markets

Volatility in the capital markets continues to 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.

Subsequent Event

Distribution

On April 25, 2017, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit for the quarter ended March 31, 2017, or $1.65 per common unit on an annualized basis. The distribution is expected to be paid on May 12, 2017, to unitholders of record as of the close of business on May 5, 2017.

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Our Operations

We manage our business and analyze and report our results of operations through six 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 natural gas liquids, 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.

- Propane Marketing Services. Our Propane Marketing Services segment gathers, transports and sells natural gas liquids (NGLs). This is accomplished through cylinder tank exchange, sales through retail, commercial and wholesale distribution and through a fleet of trucks operating in the Eagle Ford and Permian basin areas.

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 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

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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. Please read the information set forth in Part I, Item 3 of this Quarterly 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 we are obligated to 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 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 we are obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the shipper utilizes the capacity. In most cases, the shipper also pays a variable-use charge with respect to quantities actually transported by us.

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

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

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

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

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

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.

Propane Marketing Services Segment

Our Propane Marketing Services segment consists of (i) portable cylinder tank exchange, (ii) NGL sales through our retail, commercial and wholesale distribution business and (iii) NGL gathering and transportation business. Currently, the cylinder exchange network covers 46 states through a network of approximately 20,000 locations, which includes grocery chains, pharmacies, convenience stores and hardware stores. Additionally, in seven states in the southwest region of the U.S., we sell NGLs to retailers, wholesalers, industrial end-users and commercial and residential customers. We also own a fleet of NGL gathering and transportation operations trucks operating in the Eagle Ford shale and the Permian Basin.

Contract Mix

For the three months ended March 31, 2017 and 2016, $54.9 million and $42.9 million, or 90.2% and 93.5%, respectively, of our gross margin (excluding propane) was generated from fee-based, fixed margin, firm and interruptible transportation contracts and firm storage contracts. Set forth below is a table summarizing our average contract mix relative to segment gross margin for the three months ended March 31, 2017 and 2016 (in thousands):

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	For the Three Months Ended March 31, 2017 Segment Gross Margin	Percent of Segment Gross Margin		For the Three Months Ended March 31, 2016 Segment Gross Margin	Percent of Segment Gross Margin	
Gas Gathering and Processing Services						
Fee-based	$4,361	39	%	$7,694	66	%
Fixed margin	1,869	17	%	1,505	13	%
Percent-of-proceeds	5,021	44	%	2,420	21	%
Total	$11,251	100	%	$11,619	100	%
Liquid Pipelines and Services						
Fee-based	$6,149	95	%	$4,792	82	%
Fixed margin	321	5	%	1,058	18	%
Percent-of-proceeds	—	—	%	—	—	%
Total	$6,470	100	%	$5,850	100	%
Natural Gas Transportation Services						
Firm transportation	$4,033	66	%	$3,889	70	%
Interruptible transportation	568	9	%	262	5	%
Fee-based	1,220	20	%	1,205	22	%
Fixed margin	298	5	%	207	3	%
Total	$6,119	100	%	$5,563	100	%
Offshore Pipelines and Services						
Firm transportation	$797	3	%	$92	1	%
Interruptible transportation	12,611	49	%	11,617	88	%
Fee-based	12,415	48	%	927	7	%
Fixed margin	(30)	—	%	625	4	%
Percent-of-proceeds	9	—	%	4	—	%
Total	$25,802	100	%	$13,265	100	%
Terminalling Services						
Firm storage	$6,953	62	%	$5,865	62	%
Refined products distribution	919	8	%	540	6	%
Fee-based	3,288	30	%	3,038	32	%
Total	$11,160	100	%	$9,443	100	%
Propane Marketing Services						
Distribution	$19,302	100	%	$28,305	100	%
Total	$19,302	100	%	$28,305	100	%

Cash distributions derived from our unconsolidated affiliates amounted to $22.5 million and $13.5 million for the three months ended March 31, 2017 and 2016, 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, 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, crude oil, 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 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. 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.

In our Propane Marketing Services segment the amount of revenue we generate depends on the gallons of NGLs we sell through our cylinder exchange and NGL sales businesses. In addition, our NGL transportation operations generate revenue based on the number of gallons of NGLs we gather and the distance we transport those gallons for our customers. Revenues in this segment are also impacted by changes in the market price of commodities that we pass through to our customers.

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 Gross Margin

Segment gross margin and 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 or plus unrealized losses on commodity derivatives, construction and operating management agreement income and the cost of natural gas, and NGLs and condensate purchased.

We define segment gross margin in our Liquid Pipelines and Services segment as total revenue plus unconsolidated affiliate earnings less unrealized gains or plus unrealized losses on commodity derivatives and the cost of crude oil purchased in connection

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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 natural gas purchased in connection with fixed-margin arrangements. Substantially all of our gross margin in this segment is fee-based or fixed-margin, with little to no direct commodity price risk.

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

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

We define segment gross margin in our Propane Marketing Services segment as total revenue less purchases of natural gas, NGLs and condensate excluding non-cash charges such as non-cash unrealized gains or plus unrealized losses on commodity derivatives.

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

Operating Margin

Operating margin is a supplemental non-GAAP financial metric that we use to evaluate our performance. 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 income (loss) attributable to the Partnership. For a reconciliation of Operating Margin to net income (loss), please read “- Non-GAAP Financial Measures.”

Direct Operating Expenses

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

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure used by our management and external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess: the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash flow to make cash distributions to our unitholders and our General Partner; our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

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

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Non-GAAP Financial Measures

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

The following tables reconcile the non-GAAP financial measures of 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 three months ended March 31, 2017 and 2016 (in thousands):

	Three months ended March 31,	
	2017	2016
Reconciliation of Segment Gross Margin to Net income (loss) attributable to the Partnership:		
Gas Gathering and Processing Services segment gross margin	$11,251	$11,619
Liquid Pipelines and Services segment gross margin	6,470	5,850
Natural Gas Transportation Services segment gross margin	6,119	5,563
Offshore Pipelines and Services segment gross margin	25,802	13,265
Terminalling Services segment gross margin (1)	11,160	9,443
Propane Marketing Services segment gross margin	19,302	28,305
Total Segment Gross Margin	80,104	74,045
Less:		
Other direct operating expenses (1)	27,015	27,966
Total Operating Margin	53,089	46,079
Plus:		
Loss on commodity derivatives, net	(257)	(238)
Less:		
Corporate expenses	32,844	21,101
Depreciation, amortization and accretion expense	29,351	25,041
(Gain) loss on sale of assets, net	(228)	1,122
Interest expense	17,966	8,302
Other income	(14)	(31)
Other, net	671	(365)
Income tax expense	1,123	735
Loss from discontinued operations, net of tax	—	539
Net income (loss) attributable to noncontrolling interest	1,303	(3)
Net income (loss) attributable to the Partnership	$(30,184)	$(10,600)

(1) Other direct operating expenses include Gas Gathering and Processing Services segment direct operating expenses of $8.1 million and $8.5 million, respectively, Liquid Pipelines and Services segment direct operating expenses of $2.1 million and $2.5 million, respectively, Natural Gas Transportation Services segment direct operating expenses of

$1.2 million and $1.2 million, respectively, Offshore Pipelines and Services segment direct operating expenses of $2.6 million and $2.3 million, respectively, Propane Marketing Services segment direct operating expenses of $13.1 million and $13.5 million, respectively, for the three months ended March 31, 2017 and 2016. Direct operating expenses related to our Terminalling Services segment

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of $3.1 million and $2.6 million for the three months ended March 31, 2017 and 2016, respectively, are included within the calculation of Terminalling Services segment gross margin.

	Three months ended March 31,	
	2017	2016
Reconciliation of Net income (loss) attributable to the Partnership to Adjusted EBITDA:		
Net income (loss) attributable to the Partnership	$(30,184)	$(10,600)
Add:		
Depreciation, amortization and accretion expense	29,071	25,041
Interest expense	14,935	7,600
Debt issuance costs paid	1,402	323
Unrealized (gain) loss on derivatives, net	1,273	1,382
Non-cash equity compensation expense	4,038	1,643
Transaction expenses	8,618	1,073
Income tax expense	1,123	735
Discontinued operations	—	176
Distributions from unconsolidated affiliates	22,494	13,515
General Partner contribution for cost reimbursement	9,614	1,500
Deduct:		
Earnings in unconsolidated affiliates	15,402	7,343
Other income (loss)	28	(23)
Gain (loss) on sale of assets, net	228	(1,122)
Adjusted EBITDA	$46,726	$36,190

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General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed in Part II, Item 7 of our Annual Report under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations — General Trends and Outlook."

Results of Operations — Combined Overview

Net loss attributable to the Partnership increased by $19.6 million for the three months ended March 31, 2017, as compared to the same period in 2016. For the three months ended March 31, 2017, direct operating expenses decreased by $0.5 million primarily due to lower compressor rental costs. Corporate expenses increased by $11.7 million primarily due to incremental transaction costs of $7.5 million and an increase of $3.2 million relating to salaries and severance expense. The remaining increase is attributable to increased office expense with change of locale. Interest expense increased by $9.7 million as a result of additional borrowings to fund capital growth and acquisitions. Earnings from unconsolidated affiliates increased by $8.1 million as result of our investment in the Emerald transactions and the additional investments in Delta House occurring in Q2 and Q4 2016.

Segment gross margin for the three months ended March 31, 2017 was $80.1 million compared to $74.0 million for the three months ended March 31, 2016. This increase of $6.1 million was primarily due to higher segment gross margin in our Offshore Pipelines and Services segment of $12.6 million as a result of earnings in unconsolidated affiliates and the American Panther system that was acquired in Q2 2016, slightly higher margin in our Terminalling Services segment mostly due to the expansion of the Harvey Terminal for $2.3 million. These increases were partially offset by a decrease of $9.0 million related to our Propane Marketing Services segment primarily attributable to warmer than normal temperatures during the winter's heating season.

For the three months ended March 31, 2017, Adjusted EBITDA increased $10.5 million, or 29.0%, compared to the same period in 2016. The increase is primarily related to higher distributions from our unconsolidated affiliates of $9.0 million largely due to

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our investments in Delta House and the entities underlying the Emerald Transactions and an add-back $7.5 million for transaction expenses.

We distributed $24.9 million to holders of our common units, or $0.4125 per common unit, during the three months ended March 31, 2017, and $27.0 million, or $0.4725 per common unit, during the three months ended March 31, 2016.

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

	Three months ended March 31,	
	2017	2016
Statement of Operations Data:		
Revenue:		
Commodity sales	$158,501	$107,570
Services	41,388	36,044
Gain (loss) on commodity derivatives, net	(257)	(238)
Total revenue	199,632	143,376
Operating expenses:		
Costs of sales	132,785	73,938
Direct operating expenses	30,088	30,575
Corporate expenses	32,844	21,101
Depreciation, amortization and accretion expense	29,351	25,041
Total operating expenses	225,068	150,655
(Gain) loss on sale of assets, net	(228)	1,122
Operating loss	(25,208)	(8,401)
Other income (expense), net		
Interest expense	(17,966)	(8,302)
Other income (expense)	14	31
Earnings in unconsolidated affiliates	15,402	7,343
Loss from continuing operations before taxes	(27,758)	(9,329)
Income tax expense	(1,123)	(735)
Loss from continuing operations	(28,881)	(10,064)
Loss from discontinued operations, net of tax	—	(539)
Net loss	(28,881)	(10,603)
Less: Net income (loss) attributable to noncontrolling interests	1,303	(3)
Net loss attributable to the Partnership	$(30,184)	$(10,600)
Other Financial Data:		
Gross margin (1)	$80,104	$74,045
Adjusted EBITDA (1)	$46,726	$36,190

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

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Total Revenue. Our total revenue for the three months ended March 31, 2017 was $199.6 million compared to $143.4 million for the three months ended March 31, 2016. This increase of $56.2 million was primarily due to the following:

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- an increase in our Gas Gathering and Processing Segment revenue of $11.2 million primarily due to a new contract at our Longview plant for NGLs and condensate for $14.1 million, partially offset by a decrease due to a marketing contract that ended in Q4 of 2016;
- an increase in our Liquid Pipelines and Services Segment revenue of $39.2 million due to an increase of $30.7 million due to more favorable market conditions resulting in higher realized crude prices, an increase of $2.7 million due to sales volumes resulting from an increase in producer activity on our Silver Dollar Pipeline and an increase of $4.7 million due to additional Crude Oil Sales contracts on the Bakken system added in 2017;
- an increase in our Natural Gas Transportation Services segment revenue of $2.6 million primarily due to an increase on the Magnolia system of $1.8 million due to higher average throughput mostly from additional volumes that came on in Q2 2016 coupled with higher natural gas prices and additional revenues on our AlaTenn and MLGT systems for $0.5 million due to a new firm transportation contracts;
- an increase in our Offshore Pipelines and Services segment revenue of $14.8 million due primarily to higher volumes and management fees from our acquired American Panther system for $4.8 million and increased volumes sold to the Alliance Refinery on our Gloria system for $2.4 million;
- an increase in our Terminalling Services Segment revenue of $4.4 million mostly due to an increase in sales of refined products of $2.5 million, and $1.7 million due to an expansion at our Harvey terminal; and partially offset by
- a decrease in our Propane Marketing Services segment revenue of $8.0 million primarily due to a reduction in NGL revenues from lower NGL sales and trucking revenue driven by a decline in volumes associated with oilfield services and continued warmer than normal weather during the winter season.

Cost of Sales. Our purchases of natural gas, NGLs, condensate and crude for the three months ended March 31, 2017 was $132.8 million compared to $73.9 million for the three months ended March 31, 2016. This increase of $58.8 million was mostly due to higher NGL and natural gas purchases of $11.4 million due to an increase in throughput on the Longview Plant and increased crude oil prices and volumes driven by the favorable market conditions resulting in increased producer activity for $38.0 million.

Segment Gross Margin. Gross margin for the three months ended March 31, 2017 was $80.1 million compared to $74.0 million for the three months ended March 31, 2016. This increase of $6.1 million was primarily due to higher segment gross margin in our Offshore Pipeline and Services segment of $12.5 million as a result of increased earnings in unconsolidated affiliates and the American Panther system that was acquired in Q2 2016 and slightly higher margin in our Terminalling Services segment mostly due to the expansion of the Harvey Terminal for $2.3 million. These increases were partially offset by a decrease of $9.0 million related to our Propane Marketing Services segment primarily attributable to the warmer winter temperatures.

Direct Operating Expenses. Direct operating expenses for the three months ended March 31, 2017 were $30.1 million compared to $30.6 million for the three months ended March 31, 2016. This decrease of $0.5 million was primarily due to decreased compressor rental expense of $0.7 million.

Corporate Expenses. Corporate expenses for the three months ended March 31, 2017 were $32.8 million compared to $21.1 million for the three months ended March 31, 2016. This increase of $11.7 million was primarily due to $7.6 million merger related costs which include legal, consulting services and employee severance costs; $1.8 million labor costs as a result of higher wages, increased headcount and severance expense; and $1.4 million equity compensation relating to severance costs. The remaining increase is attributable to higher office expense.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended March 31, 2017 was $29.4 million compared to $25.0 million for the three months ended March 31, 2016. This increase of $4.4 million was primarily due to incremental depreciation of fixed assets related to our Gulf of Mexico Pipeline acquired in April 2016.

Interest Expense. Interest expense for the three months ended March 31, 2017 was $18.0 million compared to $8.3 million for the three months ended March 31, 2016. This increase of $9.7 million was primarily due to interest on the 8.5% Senior Notes issued in 2016 increasing interest expense $6.4 million. The remaining increase is mainly attributable to additional borrowings under the Credit Agreement.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the three months ended March 31, 2017 was $15.4 million compared to $7.3 million for the three months ended March 31, 2016. This increase of $8.1 million was primarily due to incremental earnings of $3.6 million related to our investment in Delta House and earnings of $4.8 million from the interests in the entities underlying the Emerald Transactions which were acquired in April 2016, offset by a decrease of $0.3 million from our interests in Main Pass Oil Gathering Company (“MPOG”).

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Results of Operations — Segment Results

Gas Gathering and Processing Services Segment

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

	Three months ended March 31,	
	2017	2016
Segment Financial and Operating Data:		
Gas Gathering and Processing Services segment		
Financial data:		
Commodity sales	$28,773	$17,003
Services	5,634	6,292
Revenue from operations	34,407	23,295
Gain (loss) on commodity derivatives, net	(7)	(103)
Segment revenue	34,400	23,192
Cost of Sales	23,187	11,707
Direct operating expenses	8,065	8,548
Other financial data:		
Segment gross margin (2)	$11,251	$11,619
Operating data:		
Average throughput (MMcf/d)	207.6	225.4
Average plant inlet volume (MMcf/d) (1)	103.3	105.3
Average gross NGL production (Mgal/d) (1)	297.0	275.3
Average gross condensate production (Mgal/d) (1)	80.9	70.7

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(1) Excludes volumes and gross production under our elective processing arrangements.
(2) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Commodity sales. Commodity sales revenue for the three months ended March 31, 2017 was $28.8 million compared to $17.0 million for the three months ended March 31, 2016. This increase of $11.8 million was primarily due to the following:

- increased revenue from sales of NGLs and condensate at the Longview Plant of $14.1 million due to a new contract that started in Q1 2017 and higher realized NGL prices up an average of 35% in 2017 compared to 2016; and
- partially offsetting this was a decrease due to marketing contracts that ended in Q4 of 2016 for $3.4 million.

Services. Segment services revenue for the period ended March 31, 2017 was $5.6 million compared to $6.3 million for the three months ended March 31, 2016. The decrease is primarily due to decline in compression and gathering charges by $1.0 million on our Lavaca system, partially offset by an increase of $0.4 million at our Chatom plant due to additional production moving to Chatom.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the three months ended March 31, 2017 were $23.2 million compared to $11.7 million for the three months ended March 31, 2016. This increase of $11.5 million was primarily due to the increase of NGL and condensate sales at the Longview Plant, as mentioned above. Additionally, there was also an increase in throughput on our rail and increased freight charges due to the new contracts. Lastly, there was an increase on the Chatom system for $1.7 million due to the Bazor Ridge plant shutting down in Q4 2016 and volumes flowing to the Chatom Plant.

Segment Gross Margin. Segment gross margin for the three months ended March 31, 2017 was $11.3 million compared to $11.6 million for the period ended March 31, 2016.

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Direct Operating Expenses. Direct operating expenses of $8.1 million for three months ended March 31, 2017 declined from $8.5 million for the three months ended March 31, 2016, mainly due to our ongoing cost savings initiatives.

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 and pricing data).

	Three months ended March 31,	
	2017	2016
Segment Financial and Operating Data:		
Liquid Pipelines and Services segment		
Financial data:		
Commodity sales	$78,945	$40,919
Services	3,094	3,596
Revenue from operations	82,039	44,515
Gain (loss) on commodity derivatives, net	372	(233)
Earnings in unconsolidated affiliates	1,088	—
Segment revenue	83,499	44,282
Cost of Sales	77,077	38,654
Direct operating expenses	2,074	2,467
Other financial data:		
Segment gross margin (1)	$6,470	$5,850
Operating data:		
Average throughput Pipeline (Bbls/d)	33,080	31,749
Average throughput Truck (Bbls/d)	1,558	1,218

(1) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption “How We Evaluate Our Operations.”

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Commodity Sales. Segment revenue from crude oil for the three months ended March 31, 2017 was $78.9 million compared to $40.9 million for the three months ended March 31, 2016. The increase of $38.0 million was primarily due to an increase in revenue of $30.7 million due to more favorable market conditions resulting in higher realized crude prices, an increase of $2.7 million due to higher sales volume resulting from an increase in producer activity on our Silver Dollar Pipeline and an increase of $4.7 million due to additional Crude Oil Sales contracts on the Bakken system added in 2017.

Services revenue. Segment services revenue for the three months ended March 31, 2017 was $3.1 million compared to $3.6 million for the three months ended March 31, 2016. The decrease of $0.5 million was primarily due to a $0.3 million decline in crude oil transportation revenue due to lower volumes and price as well as $0.2 million declining trucking rates as a result of increased competition.

Cost of Sales. Purchases of crude oil for the three months ended March 31, 2017 was $77.1 million compared to $38.7 million for the three months ended March 31, 2016. The increase of $38.4 million is primarily due to the increase in crude prices and crude sales volumes driven by favorable market conditions resulting in higher realized crude prices and increased producer activity. Additionally, there was an increase of $4.9 million due to an additional Crude Oil

Sales contract on the Bakken system added in Q1 2017.

Segment Gross Margin. Segment gross margin for the period ended March 31, 2017, was $6.5 million compared to $5.9 million for the period ended March 31, 2016. Segment margin increased by $0.6 million due to the reasons discussed above.

Direct Operating Expenses. Direct operating expenses of $2.1 million for the three months ended March 31, 2017 declined from $2.5 million for the three months March 31, 2016 mainly due to our ongoing cost savings initiatives.

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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 and pricing data).

	Three months ended March 31,	
	2017	2016
Segment Financial and Operating Data:		
Natural Gas Transportation Services segment		
Financial data:		
Commodity sales	$6,868	$4,649
Services	5,570	5,146
Segment revenue	12,438	9,795
Cost of Sales	6,260	4,224
Direct operating expenses	1,235	1,227
Other financial data:		
Segment gross margin (1)	$6,119	$5,563
Operating data:		
Average throughput (MMcf/d)	390.0	477.0

(1) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the three months ended March 31, 2017 were $6.9 million compared to $4.6 million for the three months ended March 31, 2016. The increase of $2.3 million is primarily due to an increase on the Magnolia system of $1.8 million due to higher average throughput mostly from additional volumes that came on in Q2 2016 and higher natural gas prices and marketing increases for $0.4 million.

Services revenue. Segment services revenue for the period ended March 31, 2017 was $5.6 million compared to $5.1 million for the period ended March 31, 2016. This increase of $0.5 million was mostly due to new firm transportation contracts on our AlaTenn and MLGT systems.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the period ended March 31, 2017 were $6.3 million as compared to $4.2 million for the period ended March 31, 2016. This increase is primarily due to higher volumes and prices on Magnolia for $1.7 million and marketing for $0.4 million driven by higher prices.

Segment Gross Margin. Segment gross margin for the period ended March 31, 2017, was $6.1 million compared to $5.6 million for the period ended March 31, 2016. This increase of $0.5 million was primarily due to reasons discussed above.

Direct Operating Expenses. Direct operating expenses remained flat at $1.2 million for the three months ended March 31, 2017 and 2016.

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 and pricing data).

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	Three months ended March 31,	
	2017	2016
Segment Financial and Operating Data:		
Offshore Pipelines and Services segment		
Financial data:		
Commodity sales	$3,763	$2,008
Services	11,068	4,995
Revenue from operations	14,831	7,003
Earnings in unconsolidated affiliates	14,314	7,343
Segment revenue	29,145	14,346
Cost of Sales	3,343	1,081
Direct operating expenses	2,579	2,253
Other financial data:		
Segment gross margin (1)	$25,802	$13,265
Operating data:		
Average throughput (MMcf/d)	404.0	431.0

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(1) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the three months ended March 31 2017 was $3.8 million compared to $2.0 million for the three months ended March 31, 2016. This increase of $1.8 million was primarily due to increased volumes sold to the Alliance Refinery on our Gloria system for $2.4 million partially offset by $0.4 million decrease on our Lafitte system.

Services revenue. Segment services revenue for the period ended March 31, 2017 was $11.1 million compared to $5.0 million for the period ended March 31, 2016. This increase of $6.1 million was mostly due to higher management fees and volumes related to the addition of American Panther of $5.2 million, an increase of $0.5 million off additional interruptible volume as a result of a third party pipeline outage and an increase of $0.4 million on our Gloria system due to a new firm contract.

Earnings in unconsolidated affiliates. Earnings for the quarter ended March 31, 2017 were $14.3 million compared to $7.3 million for the quarter ended March 31,2016. The increase was due to the additional Delta House acquisitions in Q2 and Q4 2016, which is continuing to perform near nameplate capacity as a result of strong performance by the producers behind it.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the period ended March 31, 2017 were $3.3 million compared to $1.1 million for the period ended March 31, 2016. This increase was mainly due to additional throughput on our Gloria system.

Segment Gross Margin. Segment gross margin for the period ended March 31, 2017 was $25.8 million compared to $13.3 million for the period ended March 31, 2016. This increase of $12.5 million was primarily due to earnings in unconsolidated affiliates and from our American Panther system as noted above.

Direct Operating Expenses. Direct operating expenses of $2.6 million and $2.3 million for the three months March 31, 2017 and 2016 remained relatively consistent period over period.

Terminalling Services Segment

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

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	Three months ended March 31,	
	2017	2016
Segment Financial and Operating Data:		
Terminalling Services segment		
Financial data:		
Commodity sales	$5,172	$2,702
Services	13,454	11,691
Revenue from operations	18,626	14,393
Loss on commodity derivatives, net	—	(175)
Segment revenue	18,626	14,218
Cost of Sales	4,393	2,205
Direct operating expenses	3,073	2,609
Other financial data:		
Segment gross margin (2)	$11,160	$9,443
Operating data:		
Contracted Capacity (Bbls)	5,299,667	4,519,300
Design Capacity (Bbls)*	5,400,800	4,800,800
Storage utilization (1)	98.1 %	94.1 %
Terminalling and Storage throughput (Bbls/d)	56,279	58,639

(1) Excludes storage utilization associated with our discontinued operations.
(2) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Commodity Sales. Segment commodity sales for the three months ended March 31, 2017 was $5.2 million compared to $2.7 million for the three months ended March 31, 2016. The increase of $2.5 million relates to our refined products and is driven by the timing of our sale of excess product gain and butane blending volumes of $1.2 million and higher realized sales price of $1.3 million.

Services Revenue. Segment services revenue for the three months ended March 31, 2017 was $13.5 million compared to $11.7 million for the three months ended March 31, 2016. This increase is primarily driven by the increase in storage capacity as a result of the expansion efforts at the Harvey terminal.

Cost of Sales. Segment purchases of natural gas, NGLs and condensate for the three months ended March 31, 2017 was $4.4 million compared to $2.2 million for the three months ended March 31, 2016. The increase of $2.2 million is due to the increase in sales of our butane blending volumes.

Segment Gross Margin. Segment adjusted gross margin for the three months ended March 31, 2017 was $11.2 million compared to $9.4 million for the three months ended March 31, 2016. The $1.8 million increase in gross margin is mostly driven by $1.0 million from the Harvey storage expansion and $0.7 million increase in product gain and butane blending volumes as noted above.

Direct Operating Expenses. Segment direct operating expense for the three months ended March 31, 2017 was $3.1 million and remained flat compared to $2.6 million for the three months ended March 31, 2016. Mainly driven by higher personnel and operating costs related to our Harvey expansion.

Propane Marketing Services Segment

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

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	Three months ended March 31, 2017	2016
Segment Financial and Operating Data:		
Propane Marketing Services segment		
Financial data:		
Commodity sales	$34,980	$40,289
Services	2,568	4,324
Revenue from operations	37,548	44,613
Gain (loss) on commodity derivatives, net	(622)	273
Segment revenue	36,926	44,886
Cost of Sales	18,525	16,067
Direct operating expenses	13,062	13,471
Other financial data:		
Segment gross margin (1)	$19,302	$28,305
Operating data:		
NGL and refined product sales (Mgal/d)	202	237

(1) For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, please read the information in this Item under the caption “How We Evaluate Our Operations.”

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the three months ended March 31, 2017 were $35.0 million compared to $40.3 million for the three months ended March 31, 2016. This decrease of $8.4 million was due to a reduction of NGL revenues due to lower NGL sales and trucking volumes driven by a decline in volumes associated with oilfield services and continued overall warmer than normal temperatures during winter .

Services Revenue. Services revenue for the three months ended March 31, 2017 was $2.6 million compared to $4.3 million for the three months ended March 31, 2016. This decrease of $1.7 million was due to the same business drivers as described in the ‘Commodity Sales’ section above.

Cost of Sales. Segment purchases of natural gas, NGLs and condensate for the three months ended March 31, 2017 was $18.5 million compared to $16.1 million for the three months ended March 31, 2016. The increase is due to higher propane prices in the three months ended March 31, 2017 compared to the same period in the prior year offset by lower sales volumes.

Segment Gross Margin. Segment adjusted gross margin for the three months ended March 31, 2017 was $19.3 million compared to $28.3 million for the three months ended March 31, 2016. The decrease of $9.0 million is driven by the reduced sales revenue and increased purchase of natural gas, NGLs and condensate.

Direct Operating Expenses. Segment direct operating expenses for the three months ended March 31, 2017 was $13.1 million compared to $13.5 million for the three months ended March 31, 2016. The decrease is driven by lower distribution costs as a result of lower volumes as well as improved fleet efficiencies.

Liquidity and Capital Resources

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

Our principal sources of liquidity include cash from operating activities, borrowings under our Credit Agreement (as defined herein), or through private transactions. In addition, we may seek to raise capital through the issuance of secured and unsecured senior notes. Given our historical success in accessing various sources of liquidity, we believe that the sources of liquidity described above will be sufficient to meet our short-term working capital requirements, medium-term maintenance capital expenditure requirements, and quarterly cash distributions for at least the next four quarters. In the event these sources are not sufficient, we

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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 capex mainly through additional forms of debt or equity financing.
Changes in natural gas, crude oil, NGL and condensate prices and the terms of our contracts have a direct impact on our generation and use of cash from operations due to their impact on net income (loss), along with the resulting changes in working capital. 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, please read the information provided under Part II, Item 7A of our Annual Report under the caption, "Quantitative and Qualitative Disclosures about Market Risk" and Part I, Item 3 of this Quarterly 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 March 31, 2017, we have not been required to post collateral with our counterparties.

At-The-Market ("ATM") Offering

On October 18, 2015, we filed a prospectus supplement related to the offer and sale from time to time of common units in an at-the-market offering. For the quarter ended March 31, 2017, we did not sell any common units under our ATM program and have approximately $96.8 million remaining available for sale under the Partnership's ATM Equity Offering Sales Agreement.

Our Credit Agreement

On March 8, 2017, we entered into the Second Amended and Restated Credit Agreement, which increased our borrowing capacity from $750.0 million to $900.0 million and provided for an accordion feature that will permit, subject to the customary conditions, the borrowing capacity under the facility to be increased to a maximum of $1.1 billion. We can elect to have loans under our Credit Agreement bear interest either at a Eurodollar-based rate, plus a margin ranging from 2.00% to 3.25% depending on our total leverage ratio then in effect, or a base rate which is a fluctuating rate per annum equal to the highest of (i) the Federal Funds Rate, plus 0.50%, (ii) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate", or (iii) the Eurodollar Rate plus 1.00%, plus a margin ranging from 1.00% to 2.25% depending on the total leverage ratio then in effect. We also pay a commitment fee of 0.50% per annum on the undrawn portion of the revolving loan under the Credit Agreement.

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

On September 30, 2016, in connection with the 3.77% Senior Note Purchase Agreement, we entered into the Limited Waiver and Third Amendment to the Credit Agreement, which among other things, (i) allows Midla Holdings (as defined below), for so long as the 3.77% Senior Notes are outstanding, to be excluded from guaranteeing the obligations under the Credit Agreement and being subject to certain convents thereunder, (ii) releases the lien granted under the original credit agreement on D-Day’s equity interests in FPS Equity, and (iii) deems the FPS Equity excluded property under the Credit Agreement. All other terms under the Credit Agreement remain the same.

For the three months ended March 31, 2017 and 2016, the weighted average interest rate on borrowings under our Credit Agreement and the JPE revolver was approximately 4.44% and 4.07%, respectively.

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As of March 31, 2017, our consolidated total leverage ratio was 4.64 and our interest coverage ratio was 6.19, which were both in compliance with the related requirements of our Credit Agreement. At March 31, 2017 and December 31, 2016, letters of credit outstanding under the Credit Agreement were $26.6 million and $7.4 million, respectively. As of March 31, 2017, we had approximately $644.8 million of borrowings and $26.6 million of letters of credit outstanding under the Credit Agreement resulting in $228.5 million of available borrowing capacity.

Our ability to maintain compliance with the consolidated total leverage and minimum 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.

8.50% Senior Unsecured Notes

On December 28, 2016, we and American Midstream Finance Corporation, our wholly owned subsidiary (together with the Partnership, the “Issuers”) completed the issuance and sale of the 8.50% Senior Notes. The 8.50% Senior Notes were issued at par and provided approximately $294.0 million in proceeds, after deducting initial purchasers' discount of $6.0 million. We 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 Acquisition and the satisfaction of other conditions related thereto, the proceeds were used to repay and terminate JPE's revolving credit facility and reduce borrowings under our Credit Agreement.

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

3.77% Senior Secured Notes

On September 30, 2016, Midla Financing, Midla, and MLGT entered into the 3.77% Senior Note Purchase Agreement with the purchasers party thereto (the “Purchasers”). Pursuant to the 3.77% Senior Note Purchase Agreement, Midla Financing sold $60.0 million in aggregate principal amount of Senior Notes to the Purchasers, which bear interest at an annual rate of 3.77% to be paid quarterly. The 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 starting 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 $49.8 million (after deducting related issuance costs). The proceeds are contractually restricted. The 3.77% Senior Notes are non-recourse to the Partnership.

The Note Purchase Agreement includes customary representations and warranties, affirmative and negative covenants (including financial covenants), and events of default that are customary for a transaction of his type. Many of these provisions apply not only to Midla Financing and the Note Guarantors, but also to American Midstream Midla Financing Holdings, LLC (“Midla Holdings”), a wholly owned subsidiary of the Partnership and the sole member of Midla Financing. Among other things, 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 (a) until June 30, 2017, (b) 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 (c) unless certain other requirements are met.

In connection with the 3.77% Senior Note Purchase Agreement, the Note Guarantors guaranteed the payment in full of all Midla Financing’s obligations under the 3.77% Senior 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 will 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 (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.

Merger Support and Reimbursement

In recognition of the historically warm weather that adversely impacted the Propane Marketing and Services segment and the transition-related impacts of the merger during the quarter, affiliates of ArcLight, the owner of our general partner, have committed

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to effectively reimburse $9.6 million relating to overhead support. This is incremental to the commitments made in the support agreement with the Partnership that was executed in conjunction with the JPE Acquisition .

Working Capital

Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Our working capital was $27.2 million at March 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):

	Three months ended March 31,	
	2017	2016
Net cash provided by (used in):		
Operating activities	$5,767	$29,268
Investing activities	286,385	(12,567)
Financing activities	(280,899)	(17,149)

Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Operating Activities. During the three month period ended March 31, 2017, we generated $5.7 million of cash provided by operating activities, a decrease of $23.5 million when compared to the same period in 2016. The decrease in cash flows from operating activities resulted primarily from a increase of the net loss of $18.2 million and the net decrease in operating assets and liabilities of $15.6 million mainly driven by a decrease in unbilled revenue for the three months ended March 31, 2017.

Investing Activities. During the three months ended March 31, 2017, net cash provided by investing activities was $286.4 million, an increase of $299.0 million as compared to the same period in 2016. The increase of cash flows from investing activities resulted primarily from the release of $299.3 million in restricted cash in March 2017 that was held in escrow, a decrease of $8.1 million in capital expenditures, and a decrease of $3.5 million in investments made in unconsolidated affiliates when compared to the same period in 2016. Partially offsetting these items was $11.0 in proceeds on disposals of property, plant, and equipment in the three months ended March 31, 2016, without comparable activity in the current period.

Financing Activities. During the three months ended March 31, 2017, net cash used in financing activities was $280.9 million, an increase of $263.8 million as compared to the same period in 2016. The increase in cash used by financing activities resulted primarily from an increase of $266.5 in repayments on the revolving credit agreement and an increase of $3.1 million in distributions made to unitholders. Partially offsetting these items was an increase in borrowings of $10.7 million on the revolving credit agreement.

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 March 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 March 31, 2017, our off-balance sheet arrangements changed by $0.6 million from those listed in “Contractual Obligations” within Item 7: Management’s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report filed on March 28, 2017.

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Capital Requirements

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

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

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

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the three months ended March 31, 2017, capital expenditures totaled $20.2 million, including expansion capital expenditures of $16.1 million, maintenance capital expenditures of $2.1 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $2.1 million. Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our Partnership Agreement.

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 April 25, 2017, we announced that the Board of Directors of our General Partner declared a quarterly cash distribution of $0.4125 per common unit for the quarter ended March 31, 2017, or $1.65 per common unit on an annualized basis. The cash distribution is expected to be paid on May 12, 2017, to unitholders of record as of the close of business on May 5, 2017.

Critical Accounting Policies

There were no changes to our critical accounting policies from those disclosed in our Annual Report filed on March 28, 2017.

Recent Accounting Pronouncements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. We manage exposure to commodity price risk in our business segments through the structure of our sales and supply contracts and through a managed hedging program. Our risk management policy permits the use of financial instruments to reduce the exposure to changes in commodity prices that occur in the normal course of business but prohibits the use of financial instruments for trading or to speculate on future changes in commodity prices. See Note 5 to our condensed consolidated financial statements included in Part I, Item I of this Form 10-Q for additional information.

In our 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. In our 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. In our Propane Marketing Services, we are generally able to pass through the cost of products through sales prices to our customers. To the extent we enter into fixed price product sales contracts in this business, we generally hedge our supply costs using fixed price forward contracts and swap contracts. In our cylinder exchange business, we sell approximately half of our volumes pursuant to

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contracts of generally one to three years in duration, which allow us to re-negotiate prices at the time of contract renewal, and we sell the remaining volumes on demand or under month-to-month contracts and generally adjust prices on these contracts on an annual basis. We hedge a majority of the forecasted volumes under our fixed-price contracts using financial swaps, and we may also use financial swaps to manage commodity price risk on our month-to-month contracts. At times we may also terminate or unwind hedges or a portion of hedges in order to meet cash flow objectives or when the expected future volumes do not support the level of hedges. In our NGL transportation business, we do not take title to the products we transport and therefore have no direct commodity price exposure.

Sensitivity analysis

The table below summarizes our commodity-related financial derivative instruments and fair values, as well as the effect on fair value of an assumed hypothetical 10% change in the underlying price of the commodity.

Derivative Instrument	Maturity	Notional Volume	Fair Value Asset (Liability) (in thousands)	Effect of Hypothetical 10% change
Fixed price Swaps				
Propane Fixed Price (Gallons)	April 30,2017 - December 31, 2019	7,767,296	$(259)	$444
Crude Oil Fixed Price (Barrels)	May 31,2017 - June 30, 2017	61,000	(48)	136

Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income. The preceding hypothetical analysis is limited because changes in prices may or may not equal 10% and actual results may differ.

Interest Rate Risk

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. Based on our unhedged interest rate exposure to variable rate debt outstanding as of March 31, 2017, a 1% increase or decrease in interest rates would change annual interest expense by approximately $0.9 million.

We do not hold or purchase financial instruments or derivative financial instruments for trading purposes.

Credit risk

We are exposed to credit risk. Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We manage our exposure to credit risk associated with customers to whom we extend credit through analyzing the counterparties' financial condition prior to entering into an agreement, establishing credit limits, monitoring the appropriateness of these limits on an ongoing basis and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions, as deemed appropriate. We may request letters of credit, cash collateral, prepayments or guarantees as forms of credit support.

Item 4. Controls and Procedures
Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure 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 (whom we refer to as the “Certifying Officers”), as appropriate to allow timely decisions regarding required disclosure.

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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 March 31, 2017 as a result of a material weakness as described below.

Based on its evaluation of internal control over financial reporting as described above, management concluded that the Partnership did not maintain a sufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with its financial reporting requirements. Specifically, individuals within the Partnership's financial accounting and reporting functions did not have the appropriate level of expertise to ensure that complex, non-routine transactions of the Partnership were recorded appropriately. This control deficiency resulted in out-of-period adjustments recorded to the unaudited consolidated statement of operations in the fourth quarter of 2016 and a revision to the 2015 consolidated balance sheet and consolidated statement of cash flows.

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

Material Weakness Remediation

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

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended March 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Certifying Officers pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this Quarterly Report on Form 10-Q as Exhibits 31.1 and 31.2. The certifications of our Certifying Officers pursuant to 18 U.S.C. 1350 are furnished with this Quarterly Report on Form 10-Q as Exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the information about our business, financial conditions and results of operations set forth in this Quarterly Report, careful consideration should be given to the risk factors discussed under the caption "Risk Factors" in

Part I, Item 1A of our Annual Report. Such risks are not the only risks we face. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also have a material adverse effect on our business or our operations.

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Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Certificate of Limited Partnership of American Midstream Partners, LP (filed as 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 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on April 29, 2016).
3.3	First Amendment to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated June 21, 2016 (filed as 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 (filed as 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 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 8, 2017).
3.6	Composite Agreement of Limited Partnership of American Midstream Partners, LP (filed as Exhibit 3.19 to the Annual Report on Form 10-K (Commission File No. 001-35257) filed on March 28, 2017).
3.7	Certificate of Formation of American Midstream GP, LLC (filed as Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.8	Third Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on May 6, 2016).
4.1	Supplemental Indenture, dated as of March 8, 2017, by and among American Midstream Partners, LP, the Guarantors party thereto and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 14, 2017).
10.1	Second Amended and Restated Credit Agreement, dated as of March 8, 2017, by and among American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP, Bank of America, N.A., Wells Fargo Bank, National Association, Bank of Montreal, Capital One National Association, Citibank, N.A., SunTrust Bank, Natixis New York Branch, ABN AMRO Capital USA LLC, Barclays Bank PLC, Royal Bank of Canada, Santander Bank, N.A., Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 14, 2017).
31.1*	Certification of Lynn L. Bourdon III, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Eric T. Kalamaras, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Lynn L. Bourdon III, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Eric T. Kalamaras, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**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.
**	Furnished herewith.

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SIGNATURES

Pursuant to the requirements 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.

Date: May 12, 2017

AMERICAN MIDSTREAM PARTNERS, LP

By: American Midstream GP, LLC, its General Partner

By: /s/ Lynn L. Bourdon III
Lynn L. Bourdon III
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

By: /s/ Eric T. Kalamaras
Eric T. Kalamaras
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

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3.7	Certificate of Formation of American Midstream GP, LLC (filed as Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-173191) filed on March 31, 2011).
3.8	Third Amended and Restated Limited Liability Company Agreement of American Midstream GP, LLC (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on May 6, 2016).
4.1	Supplemental Indenture, dated as of March 8, 2017, by and among American Midstream Partners, LP, the Guarantors party thereto and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 14, 2017).
10.1	Second Amended and Restated Credit Agreement, dated as of March 8, 2017, by and among American Midstream, LLC, Blackwater Investments, Inc., American Midstream Partners, LP, Bank of America, N.A., Wells Fargo Bank, National Association, Bank of Montreal, Capital One National Association, Citibank, N.A., SunTrust Bank, Natixis New York Branch, ABN AMRO Capital USA LLC, Barclays Bank PLC, Royal Bank of Canada, Santander Bank, N.A., Merrill, Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC and the lenders party thereto (filed as Exhibit 10.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on March 14, 2017).
31.1*	Certification of Lynn L. Bourdon III, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Eric T. Kalamaras, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Lynn L. Bourdon III, President and Chief Executive Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Eric T. Kalamaras, Senior Vice President & Chief Financial Officer of American Midstream GP, LLC, the General Partner of American Midstream Partners, LP, for the September 30, 2016 Quarterly Report on Form 10-Q, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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**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.
**	Furnished herewith.