American Midstream Partners, LP
Form 10-Q
August 10, 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 June 30, 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, a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” or an “emerging growth 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 51,759,787 common units, 10,400,213 Series A Units, 8,792,205 Series C Units and 2,333,333 Series D Units of American Midstream Partners, LP outstanding as of August 3, 2017. Our common units trade on the New York Stock Exchange under the ticker symbol “AMID.”

Table of Contents

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 casing head 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.
Throughput	The volume of natural gas and NGL 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.

TABLE OF CONTENTS

Table of Contents

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

	June 30, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$5,903	$5,666
Restricted cash	18,965	—
Accounts receivable, net of allowance for doubtful accounts of $1,872 and $1,871, respectively	22,905	27,769
Unbilled revenue	51,123	55,646
Inventory	8,105	6,776
Other current assets	39,655	27,667
Total current assets	146,656	123,524
Risk management assets-long term	7,704	10,664
Property, plant and equipment, net	1,166,421	1,145,003
Goodwill	217,498	217,498
Restricted cash-long term	5,038	323,564
Intangible assets, net	212,990	225,283
Investment in unconsolidated affiliates	286,548	291,988
Other assets, net	9,087	11,797
Total assets	$2,051,942	$2,349,321
Liabilities, Equity and Partners' Capital		
Current liabilities		
Accounts payable	$34,156	$45,278
Accrued gas purchases	14,211	7,891
Accrued expenses and other current liabilities	87,026	81,284
Current portion of long-term debt	1,757	5,485
Total current liabilities	137,150	139,938
Asset retirement obligations	45,302	44,363
Other long-term liabilities	2,225	2,030
3.77% Senior secured notes (Non-recourse)	55,294	55,979
8.50% Senior unsecured notes	292,609	291,309
Revolving credit facility	678,042	888,250
Deferred tax liability	9,455	8,205
Total liabilities	1,220,077	1,430,074
Commitments and contingencies (Note 17)		
Convertible preferred units (Note 13)	338,195	334,090
Equity and partners' capital		
General Partner interests (953 thousand and 680 thousand units issued and outstanding as of June 30, 2017 and December 31, 2016, respectively)	(26,664)	(47,645)
Limited Partner interests (51,760 thousand and 51,351 thousand units issued and outstanding as of June 30, 2017 and December 31, 2016, respectively)	502,311	616,087
Accumulated other comprehensive income (loss)	2	(40)
Total partners' capital	475,649	568,402
Noncontrolling interests	18,021	16,755

Total equity and partners’ capital	493,670	585,157
Total liabilities, equity and partners’ capital	$2,051,942	$2,349,321

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

Table of Contents

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

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Revenue:				
Commodity sales	$153,728	$148,592	$312,229	$256,162
Services	39,698	38,611	81,086	74,655
Gains (losses) on commodity derivatives, net	207	(1,367)	(50)	(1,605)
Total revenue	193,633	185,836	393,265	329,212
Operating expenses:				
Costs of sales	128,816	115,080	261,601	189,018
Direct operating expenses	31,884	31,967	61,972	62,542
Corporate expenses	30,084	22,281	62,928	43,382
Depreciation, amortization and accretion	30,170	26,398	59,521	51,439
(Gain) loss on sale of assets, net	52	478	(176)	1,600
Total operating expenses	221,006	196,204	445,846	347,981
Operating loss	(27,373)	(10,368)	(52,581)	(18,769)
Other income (expense), net				
Interest expense	(17,152)	(10,610)	(35,118)	(18,912)
Other income	72	496	86	527
Earnings in unconsolidated affiliates	17,552	11,702	32,954	19,045
Loss from continuing operations before taxes	(26,901)	(8,780)	(54,659)	(18,109)
Income tax expense	(801)	(701)	(1,924)	(1,436)
Loss from continuing operations	(27,702)	(9,481)	(56,583)	(19,545)
Loss from discontinued operations, net of tax	—	—	—	(539)
Net loss	(27,702)	(9,481)	(56,583)	(20,084)
Less: Net income attributable to noncontrolling interests	1,462	954	2,765	951
Net loss attributable to the Partnership	$(29,164)	$(10,435)	$(59,348)	$(21,035)
General Partner’s interest in net loss	$(375)	$(107)	$(795)	$(204)
Limited Partners’ interest in net loss	$(28,789)	$(10,328)	$(58,553)	$(20,831)
Distribution declared per common unit [(1)]	$0.4125	$0.4125	$0.8250	$0.8850
Limited Partners’ net loss per common unit (See Note 15):				
Basic and diluted:				
Loss from continuing operations	$(0.72)	$(0.33)	$(1.46)	$(0.65)
Loss from discontinued operations	—	—	—	(0.01)
Net loss	$(0.72)	$(0.33)	$(1.46)	$(0.66)
Weighted average number of common units outstanding:				
Basic and diluted	51,870	51,090	51,870	51,090

[(1)] Declared and paid each quarter related to prior quarter.

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

Table of Contents

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Net loss	$(27,702)	$(9,481)	$(56,583)	$(20,084)
Unrealized gain related to postretirement benefit plan	24	21	42	35
Comprehensive loss	(27,678)	(9,460)	(56,541)	(20,049)
Less: Comprehensive income attributable to noncontrolling interests	1,462	954	2,765	951
Comprehensive loss attributable to the Partnership	$(29,140)	$(10,414)	$(59,306)	$(21,000)

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

Table of Contents

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 income (loss)	(204)	(20,831)	—	—	(21,035)	951
Issuance of common units, net of offering costs	—	2,986	—	—	2,986	—
Cancellation of escrow units	—	(6,817)	—	—	(6,817)	—
Conversion of Series B units	—	33,593	(33,593)	—	—	—
Contributions	1,791	4,000	—	—	5,791	—
Distributions	(2,351)	(62,950)	—	—	(65,301)	—
Issuance of warrant	4,481	—	—	—	4,481	—
General Partner's contribution for acquisition	990	—	—	—	990	—
Contributions from noncontrolling interest owners	—	—	—	—	—	1,980
LTIP vesting	(2,107)	2,107	—	—	—	—
Tax netting repurchase	—	(309)	—	—	(309)	—
Equity compensation expense	1,538	942	—	—	2,480	—
Post-retirement benefit plan	—	—	—	35	35	—
Addition of Mesquite NCI		—	—	—	—	475
Balances at June 30, 2016	$(42,953)	$706,109	$ —	$ 75	$663,231	$ 15,517
Balances at December 31, 2016	$(47,645)	$616,087	$ —	$ (40)	$568,402	$ 16,755
Net income (loss)	(795)	(58,553)	—	—	(59,348)	2,765
Contributions	23,130	4,000	—	—	27,130	—
Distributions	(594)	(63,574)	—	—	(64,168)	—
Contributions from noncontrolling interests owners	—	—	—	—	—	296
Distributions to noncontrolling interests owners	—	—	—	—	—	(1,795)
LTIP vesting	(4,633)	4,633	—	—	—	—
Tax netting repurchase	—	(1,642)	—	—	(1,642)	—
Equity compensation expense	3,873	1,360	—	—	5,233	—
Post-retirement benefit plan	—	—	—	42	42	—
Balances at June 30, 2017	$(26,664)	$502,311	$ —	$ 2	$475,649	$ 18,021

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

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

	Six months ended June 30, 2017	Six months ended June 30, 2016
Cash flows from operating activities		
Net loss	$(56,583)	$(20,084)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, amortization and accretion	59,521	51,650
Amortization of deferred financing costs	2,456	1,512
Amortization of weather derivative premium	475	451
Unrealized loss on derivatives contracts, net	3,020	4,870
Non-cash compensation expense	5,233	3,051
(Gain) loss on sale of assets, net	(176)	1,486
Corporate overhead support	4,000	4,000
Other non cash items	1,906	(709)
Earnings in unconsolidated affiliates	(32,954)	(19,045)
Distributions from unconsolidated affiliates	32,954	19,045
Deferred tax expense	1,250	835
Bad debt expense	515	(61)
Changes in operating assets and liabilities, net of effects of assets acquired and liabilities assumed:		
Accounts receivable	4,238	(1,223)
Inventory	(1,738)	(5,668)
Unbilled revenue	4,523	6,686
Risk management assets and liabilities	(1,157)	(1,030)
Other current assets	(6,394)	8,149
Other assets, net	147	896
Restricted cash	(3,135)	—
Accounts payable	(12,069)	(8,446)
Accrued gas purchases	6,320	2,285
Accrued expenses and other current liabilities	13,216	1,749
Asset retirement obligations	(45)	(10)
Other liabilities	(247)	(673)
Net cash provided by operating activities	25,276	49,716
Cash flows from investing activities		
Acquisitions, net of cash acquired and settlements (Note 3)	(32,000)	(3,073)
Investments in unconsolidated affiliates - Emerald (Note 9)	—	(100,908)
Additions to property, plant and equipment	(44,039)	(54,658)
Proceeds from disposals of property, plant and equipment	121	11,434
Insurance proceeds from involuntary conversion of property, plant and equipment	150	—
Investments in unconsolidated affiliates	—	(11,444)
Distributions from unconsolidated affiliates, return of capital	5,440	16,673
Restricted cash	302,643	—
Net cash provided by (used in) investing activities	232,315	(141,976)
Cash flows from financing activities		
Proceeds from issuance of common units to public, net of offering costs	—	2,986
Contributions	23,130	1,791

Distributions	(60,494)	(53,983)
Contribution from noncontrolling interest owners	296	1,980
Distributions to noncontrolling interests owners	(1,795)	—
LTIP tax netting unit repurchase	(1,642)	(309)
Payment of financing costs	(2,116)	(1,475)
Payments on 3.77% Senior Notes	(1,078)	—

Table of Contents

	Six months ended June 30,	
	2017	2016
Payments on other debt	(3,447)	(1,810)
Payments on credit agreement	(383,908)	(101,900)
Borrowings on credit agreement	173,700	245,200
Other	—	(166)
Net cash provided by (used in) financing activities	(257,354)	92,314
Net increase in cash and cash equivalents	237	54
Cash and cash equivalents		
Beginning of period	5,666	1,987
End of period	$5,903	$2,041

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

Table of Contents

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.

JPE Acquisition

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 JPE 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 defined below).

As both we and JPE were controlled by ArcLight affiliates, the acquisition represented 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 of their investment in us 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) liquid 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. See Note 21 - Subsequent Events
regarding the announced sale of substantially all of our propane marketing services segment in July 2017.

Most of our cash flow is generated from fee-based and fixed-margin arrangements 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 natural gas transportation, offshore pipelines 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 and six months ended June 30, 2017 are not necessarily indicative of results expected for

Table of Contents

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.

Summary of Significant Accounting Policies

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, historical collection experience and the age of accounts receivable. As of June 30, 2017 and December 31, 2016, the balance of allowance for doubtful accounts was $1.9 million.

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. 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 sheets as of the balance sheet date. In each case, we are not obligated to absorb losses

Table of Contents

greater than our proportional ownership percentages. Our right to receive residual returns is not limited to any amount less than the ownership percentages.

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.

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

2. 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. From March 2016 to May 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; 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 and 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 the new accounting guidance for revenue recognition will have on our consolidated financial statements and related disclosures. We also have engaged a third-party consulting firm to assist us with all the three phases of adoption of the new guidance (Impact Assessment, Convert and Implement). We will adopt the new standard on its effective date January 1, 2018 using the modified retrospective method of adoption.

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. We are still in the process of evaluating the impact of ASU 2016-02 on our consolidated financial statements as we will be required to reflect our various lease obligations and associated asset use rights on our consolidated balance sheets. The adoption may also impact our debt covenant compliance and may require us to modify or replace certain of our existing information systems. We will adopt the guidance on its effective date January 1, 2019.

In August 2016, the FASB issued ASU No. 2016-15, “Statement of Cash Flows (Topic 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. The retrospective transition method of adoption is required unless it is impracticable. Early adoption is permitted, but only if all aspects are adopted in the same period. We are still evaluating the impact of this update on our consolidated statements of cash flows and the related disclosures. We will adopt the standard upon its effective date January 1, 2018.

In November 2016, the FASB issued ASU No. 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash”, which aims to improve the disclosure of the change during the period in total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash or restricted cash equivalents should be included

Table of Contents

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 have evaluated the impact of this update and believe it will have a material impact on our consolidated statement of cash flows and related disclosures, upon our effective date of adoption January 1, 2018.

In January 2017, the FASB issued ASU No. 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business” The guidance provides criteria for use in determining when to conclude an integrated “set of assets and activities (as defined in the original guidance) being acquired or disposed in a transaction is not a business. Where the criteria are not met, more stringent screening has been provided to define a set as a business without an output, as more narrowly defined within the guidance. ASU No. 2017-01 is effective for annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments should be applied prospectively on or after the effective date. Early adoption is permitted. We are still in the process of evaluating the guidance and can not determine the impact of this guidance on our consolidated financial statements and related disclosures. We will adopt ASU 2017-01 on its effective date of January 1, 2018.

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 of this update on our consolidated financial statements and related disclosures and will adopt the guidance on its effective date January 1, 2020 using the required prospective method

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

3. Acquisitions

JP Energy Partners LP

On March 8, 2017, we completed the acquisition of JPE, a legal 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 represented a transaction among entities under common control. Although we were 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 of us 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.

Table of Contents

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.

Acquisition of Viosca Knoll

On June 2, 2017 (“acquisition date”), we acquired 100% of the Viosca Knoll System (“Viosca Knoll”) from Genesis Energy, L.P. for total consideration of approximately $32 million in cash. The Viosca Knoll System serves producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico and connects to several major delivery pipelines including the Partnership’s High Point and Destin pipelines. Viosca Knoll will provide greater East-West Gulf connectivity, through the connection of the High Point Gas Transmission system and the Destin Pipeline, both controlled by us. The Viosca Knoll acquisition was funded with the Partnership’s revolving credit facility and Viosca Knoll was added to our Offshore pipeline and services segment.

In accordance with ASC Topic 805 - Business Combinations, we accounted for Viosca Knoll acquisition as an acquisition of a business, with the Partnership as the acquirer. ASC 805 requires, among other things, that the consideration transferred be measured at the current market price as of the acquisition date and the asset acquired and liabilities assumed be measured at their fair value as of the acquisition date. The total consideration transferred of $32 million cash was allocated 100% to Viosca Knoll’s assets as shown below.

The following table presents our aggregated preliminary allocation of the purchase price based on estimated fair values of assets acquired as of June 30, 2017 (in thousands):

	Purchase Price Allocation
Property, plant and equipment:	
Pipelines	$ 12,266
Equipment	16,484
Total property, plant and equipment	28,750
Intangible assets	3,250
Total cash consideration	$ 32,000

The purchase price allocation is subject to the measurement period that ends at the earlier of twelve months from the acquisition date or when information becomes available.

Pro Forma Financial Information

The following table presents selected unaudited pro forma information for the Partnership assuming the acquisition of Viosca Knoll had occurred as of January 1, 2016. This pro forma information does not purport to represent what the Partnership’s actual results would have been if the acquisition had occurred as of the date indicated or what such results would be for any future periods.

The unaudited pro forma financial information consists of the following (in thousands):

	Six Months Ended

	June 30, 2017	June 30, 2016
Revenue	$396,254	$333,837
Income (loss) from continuing operations	$(56,407)	$(17,962)

Table of Contents

4. Inventory

Inventory consists of the following (in thousands):

	June 30, 2017	December 31, 2016
Crude oil	$ 2,741	$ 1,216
NGLs	3,207	3,482
Refined products	413	291
Materials, supplies and equipment	1,744	1,787
Total inventory	$ 8,105	$ 6,776

5. Other Current Assets

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

	June 30, 2017	December 31, 2016
Prepaid insurance	$ 5,109	$ 9,702
Insurance receivables	6,162	2,895
Due from related parties	20,853	4,805
Other receivables	2,363	2,998
Risk management assets	1,772	964
Other assets	3,396	6,303
Total other current assets	$ 39,655	$ 27,667

6. 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, Derivatives and Hedging, 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 (as an asset or liability) and the difference between the fair value and the contract amount is 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 volumes of our outstanding commodity-related derivatives, excluding those contracts that qualified for the NPNS exception as of June 30, 2017 and December 31, 2016, none of which were designated as hedges for accounting purposes.

Table of Contents

	June 30, 2017		December 31, 2016	
Commodity Swaps	Volume	Maturity	Volume	Maturity
Propane Fixed Price (gallons)	10,892,201	July 1, 2017 - December 31, 2019	4,364,880	January 31, 2017 - November 30, 2018
Crude Oil Fixed Price (barrels)	68,000	July 1, 2017 - July 31, 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, as defined in Note 12 - Debt Obligations, 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.

Our outstanding interest rate swap contracts' fair value consist of the following (in thousands):

Notional Amount	Term	As of June 30, 2017	As of December 31, 2016
$100,000	July 1, 2017 through December 29, 2017	$119	$ —
$100,000	December 29, 2017 through January 29, 2019	208	—
$200,000	July 1, 2017 through September 3, 2019	1,711	1,912
$100,000	January 1, 2018 through December 31, 2021	2,385	3,090
$150,000	January 1, 2018 through December 31, 2022	3,944	5,219
		$8,367	$ 10,221

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

Weather Derivative

In the second quarter of 2017, we entered into a yearly 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 passes 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 $1.1 million and $1.0 million in premiums during the six months ended June 30, 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 $1.1 million and $0.4 million as of June 30, 2017 and December 31, 2016, respectively, and are included in Other current assets on the condensed consolidated balance sheets.

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

16

Table of Contents

Type	Balance Sheet Classification	Asset Derivatives June 30, 2017	Asset Derivatives December 31, 2016	Liability Derivatives June 30, 2017	Liability Derivatives December 31, 2016
Commodity swaps	Other current assets	$234	$ 607	$ —	$ —
Commodity swaps	Accrued expenses and other current liabilities	—	—	(404)	(1)
Commodity swaps	Risk management assets - long term	—	37	—	—
Commodity swaps	Other liabilities	—	—	(196)	(1)
Interest rate swaps	Other current assets	663	—	—	—
Interest rate swaps	Accrued expenses and other current liabilities	—	—	—	(252)
Interest rate swaps	Risk management assets- long term	7,704	10,628	—	—
Weather derivatives	Other current assets	$1,110	$ 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 that are subject to enforceable master netting arrangements (in thousands):

Balance Sheet Classification	Gross Risk Management Position June 30, 2017	Gross Risk Management Position December 31, 2016	Netting Adjustments June 30, 2017	Netting Adjustments December 31, 2016	Net Risk Management Position June 30, 2017	Net Risk Management Position December 31, 2016
Other current assets	$2,006	$ 1,036	$(234)	$ (72)	$1,772	$ 964
Risk management assets- long term	7,704	10,665	—	(1)	7,704	10,664
Total assets	$9,710	$ 11,701	$(234)	$ (73)	$9,476	$ 11,628
Accrued expenses and other liabilities	$(404)	$ (253)	$234	$ 72	$(170)	$ (181)
Other liabilities	(196)	(1)	—	1	(196)	—
Total liabilities	$(600)	$ (254)	$234	$ 73	$(366)	$ (181)

For each of the three and six months ended June 30, 2017 and 2016 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):

Statement of Operations Classification	Three months ended June 30, Realized	Three months ended June 30, Unrealized	Six months ended June 30, Realized	Six months ended June 30, Unrealized
2017				
Gains (losses) on commodity derivatives, net	$260	$ (53)	$960	$ (1,010)
Interest expense	—	(1,693)	(70)	(2,010)
Direct operating expenses	(218)	—	(475)	—
Total	$42	$ (1,746)	$415	$ (3,020)
2016				
Losses on commodity derivatives, net	$(388)	$ (979)	$(776)	$ (829)
Interest expense	(32)	(2,510)	(32)	(4,041)
Direct operating expenses	(231)	—	(451)	—
Total	$(651)	$ (3,489)	$(1,259)	$ (4,870)

17

Table of Contents

7. Property, Plant and Equipment, Net

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

	Useful Life (in years)	June 30, 2017	December 31, 2016
Land	Infinite	$23,098	$ 23,520
Construction in progress	N/A	46,657	131,448
Buildings and improvements	4 to 40	24,280	24,225
Transportation equipment	5 to 15	45,090	44,060
Processing and treating plants [(1)]	8 to 40	141,109	120,977
Pipelines, compressors and right-of-way [(1)]	3 to 40	909,963	804,815
Storage	3 to 40	210,291	210,579
Equipment	3 to 31	124,607	102,409
Total property, plant and equipment		1,525,095	1,462,033
Accumulated depreciation [(1)]		(358,674)	(317,030)
Property, plant and equipment, net		$1,166,421	$ 1,145,003

[(1)] The Partnership has revised the December 31, 2016 amounts above from those amounts previously reported in its Form 10-Q for the quarter ended March 31, 2017 to primarily decrease the amount for Processing and treating plants by approximately $16 million and to increase the amount for Pipelines, compressors and rights-of-way by approximately $49.9 million, with the offsetting change to Accumulated depreciation of approximately $33.9 million.

At June 30, 2017 and December 31, 2016, gross property, plant and equipment included $253.5 million and $291.1 million, respectively, related to our FERC regulated interstate and intrastate assets.

Depreciation expense totaled $21.3 million and $20.8 million for the three months ended June 30, 2017 and 2016, respectively, and $42.9 million and $40.5 million for the six months ended June 30, 2017 and 2016, respectively.

Capitalized interest was $0.5 million for each of the three months ended June 30, 2017 and 2016, and $1.5 million and $1.0 million for the six months ended June 30, 2017 and 2016, respectively.

8. Goodwill and Intangible Assets, Net

Goodwill as of June 30, 2017 and December 31, 2016 consisted of the following (in thousands):

	June 30, 2017	December 31, 2016
Liquid Pipelines and Services [(1)]	$113,669	$ 113,669
Terminalling Services [(1)]	88,466	88,466
Propane Marketing Services	15,363	15,363
Total	$217,498	$ 217,498

[(1)] The Partnership has revised the December 31, 2016 amounts by segment above from those amounts previously reported in its Form 10-Q for the quarter ended March 31, 2017 to increase the Terminalling Services segment by approximately $11 million with the offset being to decrease the Liquid Pipelines and Services segment by the same amount.

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 44 years. Intangible assets, net, consist of the following (in thousands):

Table of Contents

	June 30, 2017		
	Gross carrying amount	Accumulated amortization	Net carrying amount
Customer relationships	$133,503	$ (35,834)	$97,669
Customer contracts	98,844	(43,142)	55,702
Dedicated acreage	53,350	(5,328)	48,022
Collaborative arrangements	11,884	(990)	10,894
Noncompete agreements	3,423	(3,250)	173
Other	751	(221)	530
Total	$301,755	$ (88,765)	$212,990

	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 $8.3 million and $5.2 million for the three months ended June 30, 2017 and 2016, respectively, and $15.5 million and $10.3 million for the six months ended June 30, 2017 and 2016, respectively.

9. Investment in unconsolidated affiliates

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

	Delta House [1]		Emerald Transactions [2]					
	FPS	OGL	Destin	Tri-States	Okeanos	Wilprise	MPOG [3]	Total
Ownership % at December 31, 2016 and June 30, 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	15,529	6,571	5,116	2,161	3,692	408	(523)	32,954
Distributions	(8,753)	(7,137)	(12,119)	(2,626)	(6,667)	(392)	(700)	(38,394)
Balances at June 30, 2017	$71,259	$24,884	$103,879	$54,557	$24,084	$4,960	$2,925	$286,548

[1] Represents direct and indirect ownership interests in Class A Units.
[2] Represents our Emerald equity method investments which were acquired in the second quarter of 2016.

(3) Main Pass Oil Gathering.

Table of Contents

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

Balance Sheets:	June 30, 2017	December 31, 2016
Current assets	$105,211	$ 120,167
Non-current assets	1,337,201	1,369,492
Current liabilities	121,966	133,085
Non-current liabilities	$489,080	$ 541,312

	Three months ended June 30,		Six months ended June 30,	
Statements of Operations:	2017	2016	2017	2016
Revenue	$105,373	$89,541	$203,366	$184,757
Gross profit	96,442	83,045	185,075	169,668
Net income	$76,414	$67,937	$145,532	$136,387

10. Accrued Expenses and Other Current Liabilities

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

	June 30, 2017	December 31, 2016
Due to related parties	$15,694	$ 4,072
Accrued interest	8,470	5,743
Legal accrual	8,192	—
Capital expenditures	7,240	14,499
Convertible preferred unit distributions	6,735	7,103
Current portion of asset retirement obligation	6,495	6,499
Additional Blackwater acquisition consideration	5,000	5,000
Employee compensation	4,967	10,804
Taxes payable	3,902	1,688
Royalties payable	3,536	3,926
Customer deposits	3,092	3,080
Gas imbalances payable	1,580	1,098
Transaction costs	1,179	3,000
Deferred financing costs	—	2,743
Recoverable gas costs	238	1,126
Other	10,706	10,903
Total accrued expenses and other current liabilities	$87,026	$ 81,284

11. 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 and 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

Table of Contents

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 17 - Commitments and Contingencies.

The following table presents activity in our asset retirement obligations for the six months ended June 30, 2017 (in thousands):

Non-current balance	$44,363
Current balance	6,499
Balances at December 31, 2016	$50,862
Expenditures	(49)
Accretion expense	984
Balances at June 30, 2017	$51,797
Less: current portion	6,495
Noncurrent asset retirement obligation	$45,302

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 June 30, 2017 and December 31, 2016.

12. Debt Obligations

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

	June 30, 2017	December 31, 2016
Revolving credit facility	$678,042	$ 888,250
8.5% Senior unsecured notes, due 2021	300,000	300,000
3.77% Senior secured notes, due 2031 (non-recourse)	58,922	60,000
Other debt [2]	685	3,809
Total debt obligations	1,037,649	1,252,059
Unamortized debt issuance costs [1]	(9,776)	(11,036)
Total debt	1,027,873	1,241,023
Less: Current portion, including unamortized debt issuance costs	(1,556)	(5,485)
Long term debt	$1,026,317	$ 1,235,538

[1] Unamortized debt issuance costs related to the revolving credit facility are included in our condensed consolidated balance sheets in Other assets, net.

[2] Other debt includes capital lease and miscellaneous long-term obligations, which are reported in Current portion of debt and Other liabilities line items on our condensed consolidated balance sheets.

Revolving Credit Facility

On March 8, 2017, we entered into the Second Amended and Restated Credit Agreement with Bank of America N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders (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, subject to 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 Credit Agreement matures on September 5, 2019.

Table of Contents

The Credit Agreement contains certain financial covenants that are applicable as of the end of any fiscal quarter, including a consolidated total leverage ratio which requires our indebtedness not to exceed 5.00 times adjusted consolidated EBITDA (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 June 30, 2017, we had approximately $678.0 million of borrowings and $32.3 million of letters of credit outstanding under the Credit Agreement resulting in $189.6 million of available borrowing capacity.

As of June 30, 2017, our consolidated total leverage ratio was 4.79 and our interest coverage ratio was 5.04, 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 six months ended June 30, 2017 and 2016, the weighted average interest rate on borrowings under our Credit Agreement and the JPE Revolver was approximately 4.67% and 4.15%, respectively.

8.50% Senior Unsecured Notes

On December 28, 2016, we and American Midstream Finance Corporation, our wholly-owned subsidiary (the “Issuers”), completed the issuance and sale of $300 million in aggregate principal amount of senior notes due 2021 (the “8.50% Senior Notes”). The 8.50% Senior Notes are jointly and severally guaranteed by certain of our existing direct and indirect wholly owned subsidiaries that guarantee our Credit Agreement. 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 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 the JPE Revolver and reduce borrowings under the 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.

As of June 30, 2017, the fair value of the 8.50% Senior Notes was $303.3 million. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

3.77% Senior 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 (the “Note Purchase 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.

Table of Contents

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 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.

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

Net proceeds from the 3.77% Senior Notes are restricted and are to 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.

As of June 30, 2017, the fair value of the 3.77% Senior Notes was $55.5 million. This estimate was based on similar private placement transactions along with changes in market interest rates which represent a Level 2 measurement.

13. Convertible Preferred Units

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

	Series A		Series C		Series D		Total
	Units	$	Units	$	Units	$	$
December 31, 2016	10,107	$181,386	8,792	$118,229	2,333	$34,475	$334,090
Paid in kind unit distributions	293	4,105	—	—	—	—	4,105
June 30, 2017	10,400	$185,491	8,792	$118,229	2,333	$34,475	$338,195

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 June 30, 2017, the conversion price is $15.69 and the conversion ratio is 1 to 1.1054.

Table of Contents

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 June 30, 2017, the conversion price is $15.69 and the conversion ratio is 1 to 1.1054.

As conversion is at the option of the holder and redemption is contingent upon a future event which is outside the control of the Partnership, the Series A-1 and A-2 Units have been classified as mezzanine equity in the condensed consolidated balance sheets.

Third Amendment to Partnership Agreement

On March 8, 2017, the Partnership 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 June 30, 2017, the conversion price is $13.79 and the conversion ratio is 1 to 1.0035.

Table of Contents

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.

As conversion is at the option of the holder and redemption is contingent upon a future event which is outside the control of the Partnership, the Series C Units have been classified as mezzanine equity in the condensed consolidated balance sheets.

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 (the “ Series D Determination Date”), 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. On July 14, 2017, the Partnership entered into an amendment to the related agreement and Amendment No. 5 to the Partnership Agreement, pursuant to which the Series D Warrant Determination Date was extended to August 31, 2017.

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 June 30, 2017, the conversion price is $14.83 and the conversion ratio is 1 to 1.0035.

As conversion is at the option of the holder and redemption is contingent upon a future event which is outside the control of the Partnership, the Series D Units have been classified as mezzanine equity in the condensed consolidated balance sheets.

14. Partners’ Capital

Our capital accounts are comprised of approximately 1.3% notional General Partner interests and 98.7% limited partner interests as of June 30, 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.

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	—	373
Issuance of GP units	273	—
Issuance of common units	—	21
Balances at June 30, 2017	953	51,745

Table of Contents

General Partner Units

In order to maintain the ownership percentage, we received proceeds of $3.9 million from our General Partner as consideration for the issuance of 272,811 additional notional General Partner units for the six months ended June 30, 2017. For the six months ended June 30, 2016, we received proceeds of $1.8 million for the issuance of 128,272 additional notional General Partner units.

Distributions

We made the following distributions (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Series A Units				
Cash Paid	$2,117	$ —	$4,644	$ —
Accrued	4,069	4,602	4,069	4,602
Paid-in-kind units	2,181	4,471	4,914	8,851
Series C Units				
Cash Paid	3,627	—	7,254	—
Accrued	3,627	2,249	3,627	2,249
Paid-in-kind units	—	—	—	—
Series D Units				
Cash Paid	963	—	1,925	—
Accrued	963	—	963	—
Limited Partner Units				
Cash Paid	21,390	24,782	46,303	51,782
General Partner Units				
Cash Paid	201	173	368	2,201
Summary				
Cash Paid	28,298	24,955	60,494	53,983
Accrued	8,659	6,851	8,659	6,851
Paid-in-kind units	2,181	4,471	4,914	8,851

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 $3.39 per unit using a Black-Scholes model, iii) assumed discount rates ranging from 5.98% to 10.0% and iv) assumed growth rates of 1.0%.

Table of Contents

15. Net Loss per Limited Partner Unit

Net 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 loss per common unit. Basic and diluted limited partners' net loss per common unit is calculated by dividing limited partners' interest in net 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 loss per common unit is summarized below (in thousands, except per unit amounts):

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Net loss from continuing operations	$(27,702)	$(9,481)	$(56,583)	$(19,545)
Less: Net income attributable to noncontrolling interests	1,462	954	2,765	951
Net loss from continuing operations attributable to the Partnership	(29,164)	(10,435)	(59,348)	(20,496)
Less:				
Distributions on Series A Units	4,069	4,602	8,367	9,073
Distributions on Series C Units	3,627	2,249	7,254	2,249
Distributions on Series D Units	963	—	1,925	—
General partner's distribution	277	173	476	2,201
General partner's share in undistributed loss	(784)	(400)	(1,541)	(818)
Net loss from continuing operations attributable to Limited Partners	(37,316)	(17,059)	(75,829)	(33,201)
Net loss from discontinued operations attributable to Limited Partners	—	—	—	(539)
Net loss attributable to Limited Partners	$(37,316)	$(17,059)	$(75,829)	$(33,740)
Weighted average number of common units used in computation of Limited Partners' net loss per common unit - basic and diluted	51,870	51,090	51,870	51,090
Limited Partners' net loss from continuing operations per unit	$(0.72)	$(0.33)	$(1.46)	$(0.65)
Limited Partners' net loss from discontinued operations per unit	—	—	—	(0.01)
Limited Partners' net loss per common unit [1]	$(0.72)	$(0.33)	$(1.46)	$(0.66)

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

16. Long-Term Incentive Plan

Our General Partner manages our operations and activities and employs the personnel who provide support to our operations. On November 19, 2015, the Board of Directors of our General Partner approved the Third Amended and Restated Long-Term Incentive Plan to, among other things, increase the number of common units authorized for issuance by 6,000,000 common units. On February 11, 2016, the unitholders approved the Third Amended and Restated Long-Term Incentive Plan (as amended and as currently in

Table of Contents

effect as of the date hereof, the “LTIP”). On March 9, 2017, an additional 312,716 common units were registered to be issued in relation to the converted JPE phantom units.

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 six months ended June 30, 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	(7,643)	21.46
Vested	(479,130)	10.32
Outstanding units at June 30, 2017	1,074,062	$ 5.39

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 expenses related to these awards were $1.2 million and $0.8 million for the three months ended June 30, 2017 and 2016, respectively, and were $5.2 million and $2.5 million for the six months ended June 30, 2017 and 2016, respectively, and are 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 $7.9 million and $0.9 million for the six months ended June 30, 2017 and 2016, respectively.

17. 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.

Table of Contents

Regulatory matters

On October 8, 2014, 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.

Acquisition 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 $0.9 million, which has been recorded as of June 30, 2017.

18. 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 balance sheets as of June 30, 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 acquisition, or if earlier, until $25 million in support has been provided. We have utilized $15.1 million of the financial support mentioned above.

During the second quarter of 2017, the Partnership received $9.6 million from the General Partner as reimbursement of post-closing transition costs. Separate from the financial support described above, our General Partner also agreed to absorb $9.6 million corporate overhead expenses, which were incurred by us in the first quarter of 2017, and subsequently paid the amount in the second quarter of 2017. These two cash amounts, and the $3.8 million received related to the General Partner's ownership percentage, totaled $23.1 million which was presented as part of the contribution line item on our condensed consolidated statements of cash flows.

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 and $0.7 million for each of the three and six months ended June 30, 2017 and June 30, 2016, respectively. As of June 30, 2017, we had a receivable balance due from Republic of $1.4 million, which is included in the account Receivables from related parties which is part of Other current assets in the condensed consolidated balance sheets.

As of June 30, 2017 and December 31, 2016, we had $2.3 million of payables balance, which is net of $15.6 million of account payables and $13.3 million of account receivables, and $3.9 million of account payables, 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.

Table of Contents

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 six months ended June 30, 2017, we recognized $1.2 million of management fee income. As of June 30, 2017 and December 31, 2016, we had an outstanding account receivables balance of $5.8 million and $2.2 million, respectively, which is recorded in Receivables from related parties and is part of Other current assets in the condensed consolidated balance sheets.

American Panther, LLC ("American Panther") is a 60%-owned subsidiary of ours which is consolidated for financial reporting purposes. Panther, a provider of midstream activities and services to the oil & gas industry in Texas, Louisiana and the Gulf Coast, is the 40% non-controlling interest owner of American Panther. Pursuant to a related party agreement which began in the second quarter of 2016, an affiliate of Panther, or Panther Offshore Gathering Systems, LLC, provides management 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 statements of operations. During the six months ended June 30, 2017, such management services totaled $0.5 million of Direct operating expenses and $0.3 million of Corporate expenses in the unaudited condensed consolidated statements 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 June 30, 2017, and 2016, we recognized revenue of $1.8 million and $0.7 million, respectively, while purchases from this company totaled $1.2 million, and $0.8 million, respectively. During the six months ended June 30, 2017, and 2016, we recognized revenue of $2.5 million and $1.6 million, respectively, while purchases from this company totaled $2.6 million and $1.8 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 six months ended June 30, 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 Mid-Continent Business with the cash flows from continuing operations for all periods presented in the condensed 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 $0 million and $4 million for the three and six months ended June 30, 2017, respectively, and $1.5 million and $4.0 million for the three and six months ended June 30, 2016, respectively. JPE’s general partner agreed to absorb $3.5 million and $5.0 million of such corporate overhead expenses in the three and six months ended June 30, 2016.

Table of Contents

19. Supplemental Cash Flow Information

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

	Six months ended June 30,	
	2017	2016
Supplemental non-cash information		
Investing		
Increase (decrease) in accrued property, plant and equipment purchases	$(7,259)	$4,856
Financing		
Contributions from an affiliate holding limited partner interests	4,000	4,000
Issuance of Series C Units and Warrant in connection with the Emerald Transactions	—	120,000
Accrued distributions on convertible preferred units	8,659	6,851
Paid-in-kind distributions on convertible preferred units	4,914	8,851
Cancellation of escrow units	—	6,817
Accrued distribution from unconsolidated affiliates	—	4,360

20. 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 and six months ended June 30, 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 Pipelines 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.

Table of Contents

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.

Table of Contents

A reconciliation from Segment Gross Margin to Net Income attributable to the Partnership for the periods presented is below (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Reconciliation of Segment Gross Margin to Net loss attributable to the Partnership:				
Gas Gathering and Processing Services segment gross margin	$12,651	$13,337	$23,902	$24,957
Liquid Pipelines and Services segment gross margin	6,683	9,432	13,152	15,284
Natural Gas Transportation Services segment gross margin	5,631	3,843	11,750	9,406
Offshore Pipelines and Services segment gross margin	25,623	20,558	51,426	33,819
Terminalling Services segment gross margin (1)	10,760	11,586	21,920	21,030
Propane Marketing Services segment gross margin	17,952	22,316	37,254	50,621
Total Segment Gross Margin	79,300	81,072	159,404	155,117
Less:				
Other direct operating expenses (1)	28,886	29,579	55,902	57,545
Plus:				
Gain (loss) on commodity derivatives, net	207	(1,367)	(50)	(1,605)
Less:				
Corporate expenses	30,084	22,281	62,928	43,382
Depreciation, amortization and accretion expense	30,170	26,398	59,521	51,439
(Gain) loss on sale of assets, net	52	478	(176)	1,600
Interest expense	17,152	10,610	35,118	18,912
Other income	(72)	(496)	(86)	(527)
Other (income) expense, net	136	(365)	806	(730)
Income tax expense	801	701	1,924	1,436
Loss from discontinued operations, net of tax	—	—	—	539
Net income attributable to noncontrolling interest	1,462	954	2,765	951
Net loss attributable to the Partnership	$(29,164)	$(10,435)	$(59,348)	$(21,035)

(1) Other direct operating expenses include Gas Gathering and Processing Services segment direct operating expenses of $8.0 million and $8.9 million, respectively, Liquid Pipelines and Services segment direct operating expenses of $1.8 million and $2.2 million, respectively, Natural Gas Transportation Services segment direct operating expenses of $1.9 million and $2.0 million, respectively, Offshore Pipelines and Services segment direct operating expenses of $3.5 million and $2.8 million, respectively, and Propane Marketing Services segment direct operating expenses of $13.6 million and $13.6 million, respectively, for the three months ended June 30, 2017 and 2016. Direct operating expenses related to our Terminalling Services segment of $3.0 million and $2.4 million for the three months ended June 30, 2017 and 2016, respectively, are included within the calculation of Terminalling Services segment gross margin.

Other direct operating expenses include Gas Gathering and Processing Services segment direct operating expenses of $16.1 million and $17.5 million, respectively, Liquid Pipelines and Services segment direct operating expenses of $3.9 million and $4.7 million, respectively, Natural Gas Transportation Services segment direct operating expenses of $3.2 million and $3.2 million, respectively, Offshore Pipelines and Services segment direct operating expenses of $6.1 million and $5.1 million, respectively, and Propane Marketing Services segment direct operating expenses of $26.7 million and $27.1 million, respectively, for the six months ended June 30, 2017 and 2016. Direct operating expenses related to our Terminalling Services segment of $6.1 million and $5.0 million for the six months ended June 30, 2017 and 2016, respectively, are included within the calculation of Terminalling Services segment gross margin.

Table of Contents

The following tables set forth our segment information for the three and six months ended June 30, 2017 and 2016 (in thousands):

	Three months ended June 30, 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	$39,307	$82,303	$ 11,397	$12,139	$ 15,831	$ 32,449	$193,426
Gain (loss) on commodity derivatives, net	(98)	297	—	—	—	8	207
Total revenue	39,209	82,600	11,397	12,139	15,831	32,457	193,633
Earnings in unconsolidated affiliates	—	1,482	—	16,070	—	—	17,552
Operating expenses:							
Cost of Sales	26,582	77,332	5,678	2,586	2,073	14,565	128,816
Direct operating expenses	8,045	1,833	1,928	3,490	2,998	13,590	31,884
Corporate expenses							30,084
Depreciation, amortization and accretion expense							30,170
Loss on sale of assets, net							52
Total operating expenses							221,006
Interest expense							17,152
Other income							(72)
Loss from continuing operations before taxes							(26,901)
Income tax expense							801
Net loss							(27,702)
Less: Net income attributable to non-controlling interests							1,462
Net loss attributable to the Partnership							$(29,164)
Segment gross margin	$12,651	$6,683	$ 5,631	$25,623	$ 10,760	$ 17,952	

Table of Contents

	Three months ended June 30, 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	$30,710	$85,415	$ 7,877	$10,645	$ 17,815	$ 34,741	$187,203
Gain (loss) on commodity derivatives, net	(763)	(716)	—	(2)	(260)	374	(1,367)
Total revenue	29,947	84,699	7,877	10,643	17,555	35,115	185,836
Earnings in unconsolidated affiliates	—	1,009	—	10,693	—	—	11,702
Operating expenses:							
Cost of Sales	17,162	76,992	4,026	778	3,542	12,580	115,080
Direct operating expenses	8,945	2,235	1,963	2,802	2,388	13,634	31,967
Corporate expenses							22,281
Depreciation, amortization and accretion expense							26,398
Loss on sale of assets, net							478
Total operating expenses							196,204
Interest expense							10,610
Other income							(496)
Loss from continuing operations before taxes							(8,780)
Income tax expense							701
Loss from continuing operation							(9,481)
Loss from discontinued operations, net of tax							$—
Net loss							(9,481)
Less: Net income attributable to non-controlling interests							$954
Net loss attributable to the Partnership							$(10,435)
Segment gross margin	$13,337	$9,432	$ 3,843	$20,558	$ 11,586	$ 22,316	

Table of Contents

	Six months ended June 30, 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	$73,714	$164,342	$ 23,835	$26,970	$ 34,457	$69,997	$393,315
Gain (loss) on commodity derivatives, net	(105)	669	—	—	—	(614)	(50)
Total revenue	73,609	165,011	23,835	26,970	34,457	69,383	393,265
Earnings in unconsolidated affiliates	—	2,569	—	30,385	—	—	32,954
Operating expenses:							
Cost of Sales	49,769	154,409	11,938	5,929	6,466	33,090	261,601
Direct operating expenses	16,110	3,906	3,163	6,070	6,071	26,652	61,972
Corporate expenses							62,928
Depreciation, amortization and accretion expense							59,521
Gain on sale of assets, net							(176)
Total operating expenses							445,846
Interest expense							35,118
Other income							(86)
Loss from continuing operations before taxes							(54,659)
Income tax expense							1,924
Net loss							(56,583)
Less: Net income attributable to non-controlling interests							2,765
Net loss attributable to the Partnership							$(59,348)
Segment gross margin	$23,902	$13,152	$ 11,750	$51,426	$ 21,920	$37,254	

Table of Contents

	Six months ended June 30, 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	$54,004	$129,930	$ 17,672	$17,645	$ 32,210	$ 79,356	$330,817
Gain (loss) on commodity derivatives, net	(866)	(948)	—	(2)	(436)	647	(1,605)
Total revenue	53,138	128,982	17,672	17,643	31,774	80,003	329,212
Earnings in unconsolidated affiliates		1,009		18,036			19,045
Operating expenses:							
Cost of Sales	28,868	115,645	8,250	1,860	5,747	28,648	189,018
Direct operating expenses	17,492	4,701	3,190	5,055	4,997	27,107	62,542
Corporate expenses							43,382
Depreciation, amortization and accretion expense							51,439
Loss on sale of assets, net							1,600
Total operating expenses							347,981
Interest expense							18,912
Other income							(527)
Loss from continuing operations before taxes							(18,109)
Income tax expense							1,436
Loss from continuing operation							(19,545)
Loss from discontinued operations, net of tax							(539)
Net loss							(20,084)
Less: Net income attributable to non-controlling interests							$951
Net loss attributable to the Partnership							$(21,035)
Segment gross margin	$24,957	$15,284	$ 9,406	$33,819	$ 21,030	$ 50,621	

37

Table of Contents

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

	June 30, 2017	December 31, 2016
Segment assets:		
Gas Gathering and Processing Services	$524,905	$530,889
Liquid Pipelines and Services	433,618	422,636
Offshore Pipelines and Services [(2)]	369,137	400,193
Natural Gas Transportation Services	227,466	221,604
Terminalling Services [(2)]	281,016	299,534
Propane Marketing Services	130,731	140,864
Other [(1)]	85,069	333,601
Total Assets	$2,051,942	$2,349,321

[(1)] Other assets not allocable to segments consist of corporate leasehold improvements and other miscellaneous assets.
[(2)] The Partnership has revised the December 31, 2016 amounts by segment above from those amounts previously reported in its Form 10-Q for the quarter ended March 31, 2017 to increase the Offshore Pipelines and Services segment by approximately $14 million and to decrease the amounts of Other and the Offshore Pipelines and Services segment by approximately $13 million and $1 million, respectively.

21. Subsequent Events

Amendment No. 5 to the Partnership Agreement

On July 14, 2017, we entered into Amendment No. 5 to the Partnership Agreement, pursuant to which the Series D Warrant Determination Date was extended to August 31, 2017.

Sale of Propane Marketing Services Business

On July 21, 2017, American Midstream Merger LP (“AMID Merger Sub”), a wholly-owned subsidiary of the Partnership, entered into a Membership Interest Purchase Agreement (“Purchase Agreement”) with SHV Energy N.V. (“SHV Energy”) pursuant to which we agreed to sell 100% of our Propane Marketing Services business, including Pinnacle Propane’s 40 service locations, Pinnacle Propane Express’ cylinder exchange business and related logistic assets, and the Alliant Gas utility system to SHV Energy, for $170 million in cash, plus balance sheet cash at closing, less the repayment of all indebtedness and transaction costs, and subject to working capital adjustments.

The transaction is expected to close in the third quarter of 2017, subject to satisfaction or waiver of certain conditions, including: (i) subject to specified materiality standards, the accuracy of the representations and warranties of each party; (ii) compliance by each party in all material respects with its covenants; (iii) expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the “HSR Act”); (iv) there being no law or injunction prohibiting the consummation of the Transaction; and (v) the receipt of consent of third parties under specified contracts or the entry into substitute contractual arrangements with respect to such contracts. The Partnership has agreed to indemnify SHV Energy for certain liabilities, including certain pre-closing tax matters, specified litigation matters and certain employment-related liabilities. Certain termination rights for both AMID Merger Sub and SHV Energy including, but not limited to, the right to terminate the Purchase Agreement in the event that (i) the transaction has not been consummated on or before October 21, 2017 or (ii) under certain conditions, if there has been a breach of certain representations and warranties or a failure to perform any covenant by the other party.

Distribution

On July 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 June 30, 2017, or $1.65 per common unit on an annualized basis. The distribution is expected to be paid on August 14, 2017, to unitholders of record as of the close of business on August 7, 2017.

Acquisitions

Table of Contents

On August 8, 2017, we announced two strategic transactions which will help to increase operating efficiency in our core areas as well as extending our participation in the value chain of our core commodities.

Acquisition of Panther

We acquired 100% of the assets of Panther Asset Management LLC ("Panther"), who is our joint venture partner in both Ampan and MPOG for a total consideration of approximately $52 million, consisting of $39 million cash from borrowings under the Partnership's revolving credit facility and common units representing limited partner interests. The underlying assets acquired are highly complementary with our core Gulf of Mexico assets as a substantial portion of Panther's cash flows are generated by our joint ventures. Through the purchase, we will now acquire Panther's 33.3% equity interests in MPOG, as well as Panther's 40% equity interest in AmPan. As such, we will now own 100% of MPOG and AmPan. This transaction allows us to both consolidate several joint ventures and moves us into an operator position for oil pipelines in the Gulf of Mexico.

Joint Venture with Targa Midstream Services, LLC

We entered into a joint venture agreement with Targa Midstream Services, LLC ("Targa") creating Cayenne Pipeline, LLC ("Cayenne"). Cayenne will transport Y-grade NGLs from the Targa-operated Venice Energy Services Company, LLC gas processing plant ("Venice") to Enterprise Products' pipeline at Toca, Louisiana, for delivery to Enterprise Products' Norco Fractionator. As part of the Cayenne joint venture, we are contributing an underutilized natural gas pipeline that will convert into high value, natural gas liquids service. The project is supported by a 15-year dedication for all NGL production from Targa's 750 MMcf/d Venice plant with inlet from six offshore pipelines in the Gulf of Mexico, including the prolific deep-water Mississippi Canyon area. The pipeline will have initial capacity of over 40,000 barrels per day with the ability to throughput more than 50,000 barrels per day. We and Targa will each have 50% economic interests and 50% voting rights, respectively, with Targa serving as the operator of the venture. The costs of conversion and associated construction will be shared equally by us and Targa.

The pipeline is expected to be operational by the end of the 4th quarter of 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.

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 generate sufficient cash from operations to pay distributions to unitholders;
- our ability to maintain compliance with financial covenants and ratios in our Credit Agreement (as defined below);

Table of Contents

- 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" of our Annual Report;
- 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) liquid 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

Table of Contents

NGLs; gathering, storing and transporting crude oil and condensates; storing specialty chemical products; and distributing and selling propane and refined products.

Our primary assets are strategically located in some of the most prolific onshore and offshore producing regions and key demand markets in the United States. Our gathering and processing assets are primarily located in (i) the Permian Basin of West Texas, (ii) the Cotton Valley/Haynesville Shale of East Texas, (iii) the Eagle Ford Shale of South Texas, and (iv) offshore in the Gulf of Mexico. Our liquid pipelines, natural gas transportation and offshore pipelines and terminal assets are located in prolific producing regions and key demand markets in Alabama, Louisiana, Mississippi, North Dakota, Texas, Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia. Additionally, 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. See Recent Developments regarding the announced sale of our Propane Marketing Services business in July 2017.

We own or have ownership interests in more than 4,100 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 17 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.

On July 14, 2017, we entered into Amendment No. 5 to our Fifth Amended and Restated Partnership Agreement (as amended, the “Partnership Agreement”). It was provided previously that if any of the Series D Units remain outstanding on June 30, 2017 (the “ Series D Determination Date”), 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 Partnership Agreement has extended the Series D Determination Date to August 31, 2017.

On July 21, 2017, we entered into a Membership Interest Purchase Agreement with SHV Energy N.V., pursuant to which we agreed to sell 100% of our Propane Marketing Services business, including Pinnacle Propane’s 40 service locations, Pinnacle Propane Express’ cylinder exchange business and related logistic assets, and the Alliant Gas utility system to SHV Energy N.V., for $170 million in cash, plus balance sheet cash at closing, less the repayment of all indebtedness and transaction costs, and subject to working capital adjustments. The transaction is expected to close in the third quarter of 2017.

Financial Highlights

Financial highlights for the three months ended June 30, 2017, include the following:

- Net loss attributable to the Partnership increased to $29.2 million, as compared to net loss of $10.4 million in the same period in 2016, primarily due to an increase in corporate expenses relating to transition costs and a significant increase in interest expenses associated with the JPE Acquisition (as defined below), partially offset by a large increase in earnings from unconsolidated affiliates;

- Earnings in unconsolidated affiliates were $17.6 million, an increase of $5.9 million as compared to the same period in 2016, primarily due to the additional Delta House investments in the second quarter and in the fourth quarter of 2016 and us having a full quarter of earnings in 2017 relating to the Emerald Transactions;

- Segment gross margin amounted to $79.3 million, or a decrease of $1.8 million as compared to the same period in 2016, primarily due to higher segment gross margin in our Offshore Pipelines and Services segment, offset by a large decrease in the segment gross margin of our Propane Marketing Services segment;

Table of Contents

- Adjusted EBITDA decreased to $44.5 million, or a decrease of 18.2% as compared to the same period in 2016, primarily due to a larger loss in 2017, and lower distributions from our unconsolidated affiliates in 2017; and

- We distributed $21.4 million to our common unitholders, or $0.4125 per common unit, the 24th consecutive distribution since our initial public offering.

Operational highlights for the three months ended June 30, 2017, include the following:

- Contracted capacity for our Terminalling Services segment averaged 5,139,367 Bbls, representing a 2.4% increase compared to the same period in 2016;

- Average condensate production totaled 79.8 Mgal/d, representing a 4.5Mgal/d or 5% decrease compared to the same period in 2016;

- Average gross NGL production totaled 398.8 Mgal/d, representing a 135.5Mgal/d or 51% increase compared to the same period in 2016;

- Throughput volumes attributable to the Natural Gas Transportation Services and Offshore Pipelines and Services segments totaled 729 MMcf/d, representing a 152 MMcf/d or 17% decrease compared to the same period in 2016;

- Throughput volumes attributable to the Liquid Pipelines and Services segment totaled 32,957 Bbls/d, representing a 1,867 Bbls/d or 6% increase compared to the same period in 2016;

- NGL and refined product sales attributable to our Propane Marketing Services segment totaled 151.6 Mgal/d, representing a decrease of 12.7 Mgal/d or 8% 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 93.2% representing a decrease of 8.8% as compared to the same period in 2016.

JPE Acquisition

On March 8, 2017, we completed the acquisition of JP Energy Partners LP (“JPE”), an entity controlled by affiliates of ArcLight Capital Partners, LLC (“ArcLight”), in a unit-for-unit merger (the “JPE 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 represented 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.

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 was consummated (which is the quarter ended March 31, 2017) and each quarter

Table of Contents

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 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 $42.53 per barrel from January 1, 2017 through July 31, 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 July 31, 2017.

Table of Contents

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. Should 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.

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

Table of Contents

simultaneously sell an identical volume of natural gas or off-spec condensate at delivery points on our systems at the same, undiscounted index price. By entering into back-to-back purchases and sales of natural gas or off-spec condensate, we are able to lock in a fixed margin on these transactions. We view the segment gross margin earned under our fixed-margin arrangements to be economically equivalent to the fee earned in our fee-based arrangements.

- Percent-of-Proceeds Arrangements (“POP”). Under these arrangements, we generally gather raw natural gas from producers at the wellhead or other supply points, transport it through our gathering system, process it and sell the residue natural gas, NGLs and condensate at market prices. Where we provide processing services at the processing plants that we own, or obtain processing services for our own account in connection with our elective processing arrangements, we generally retain and sell a percentage of the residue natural gas and resulting NGLs. However, we also have contracts under which we retain a percentage of the resulting NGLs and do not retain a percentage of residue natural gas. Our POP arrangements also often contain a fee-based component.

Gross margin earned under fee-based and fixed-margin arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, a sustained decline in commodity prices could result in a decline in throughput volumes from producers and, thus, a decrease in our fee-based and fixed-margin gross margin. These arrangements provide stable cash flows, but upside in higher commodity-price environments is limited to an increase in throughput volumes from producers. Under our typical POP arrangement, our gross margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as compensation for processing raw natural gas. However, our POP arrangements often contain a fee-based component, which helps to mitigate the degree of commodity-price volatility we could experience under these arrangements. We further seek to mitigate our exposure to commodity price risk through our hedging program. See the information set forth in Part 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.

Table of Contents

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. Our refined products terminals have butane blending capabilities.

Table of Contents

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 June 30, 2017 and 2016, $56.5 million and $51.7 million, or 93.2% and 92.4%, 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 June 30, 2017 and 2016 (in thousands):

	Three months ended June 30, 2017			Three months ended June 30, 2016		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gas Gathering and Processing Services						
Fee-based	$4,302	34	%	$7,469	56	%
Fixed margin	4,301	34	%	1,600	12	%
Percent-of-proceeds	4,048	32	%	4,268	32	%
Total	$12,651	100	%	$13,337	100	%
Liquid Pipelines and Services						
Fee-based	$5,012	75	%	$5,282	56	%
Fixed margin	1,671	25	%	4,150	44	%
Total	$6,683	100	%	$9,432	100	%
Natural Gas Transportation Services						
Firm transportation	$3,266	58	%	$3,266	85	%
Interruptible transportation	845	15	%	961	25	%
Fee-based	394	7	%	269	7	%
Fixed margin	1,126	20	%	(653)	(17	)%
Total	$5,631	100	%	$3,843	100	%
Offshore Pipelines and Services						
Interruptible transportation	8,199	32	%	10,279	50	%
Fee-based	16,912	66	%	9,662	47	%
Fixed margin	512	2	%	617	3	%
Total	$25,623	100	%	$20,558	100	%
Terminalling Services						
Firm storage	$6,133	57	%	$7,647	66	%
Refined products distribution	753	7	%	2,781	24	%
Fee-based	3,874	36	%	1,158	10	%
Total	$10,760	100	%	$11,586	100	%
Propane Marketing Services						
Distribution	$17,952	100	%	$22,316	100	%

Total	$17,952	100 %	$22,316	100 %

Cash distributions received from our unconsolidated affiliates amounted to $15.9 million and $26.6 million for the three months ended June 30, 2017 and 2016, respectively. Cash distributions derived from our unconsolidated affiliates are primarily generated from fee-based gathering and processing arrangements.

Table of Contents

For the six months ended June 30, 2017 and 2016, $111.6 million and $95.1 million, or 92.5% and 93.6%, 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 periods presented (in thousands):

	Six months ended June 30, 2017			Six months ended June 30, 2016		
	Segment Gross Margin	Percent of Segment Gross Margin		Segment Gross Margin	Percent of Segment Gross Margin	
Gas Gathering and Processing Services						
Fee-based	$8,605	36	%	$15,224	61	%
Fixed margin	6,214	26	%	3,244	13	%
Percent-of-proceeds	9,083	38	%	6,489	26	%
Total	$23,902	100	%	$24,957	100	%
Liquid Pipelines and Services						
Fee-based	$11,048	84	%	$10,087	66	%
Fixed margin	2,104	16	%	5,197	34	%
Total	$13,152	100	%	$15,284	100	%
Natural Gas Transportation Services						
Firm transportation	$7,285	62	%	$7,055	75	%
Interruptible transportation	1,998	17	%	2,163	23	%
Fee-based	939	8	%	564	6	%
Fixed margin	1,528	13	%	(376)	(4	)%
Total	$11,750	100	%	$9,406	100	%
Offshore Pipelines and Services						
Firm transportation	$1,029	2	%	$338	1	%
Interruptible transportation	21,085	41	%	21,644	64	%
Fee-based	28,799	56	%	10,822	32	%
Fixed margin	513	1	%	1,015	3	%
Total	$51,426	100	%	$33,819	100	%
Terminalling Services						
Firm storage	$13,372	61	%	$10,936	52	%
Refined products distribution	438	2	%	2,523	12	%
Fee-based	8,110	37	%	7,571	36	%
Total	$21,920	100	%	$21,030	100	%
Propane Marketing Services						
Distribution	$37,254	100	%	$50,621	100	%
Total	$37,254	100	%	$50,621	100	%

Cash distributions received from our unconsolidated affiliates amounted to $38.4 million and $40.1 million for the six months ended June 30, 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.

Table of Contents

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. Our refined products terminals have butane blending capabilities. The volume of crude oil stored at our crude oil storage facility in Cushing, Oklahoma has no impact on the revenue generated by our crude oil storage business because we receive a fixed monthly fee per barrel of shell capacity that is not contingent on the usage of our storage tanks.

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.

Table of Contents

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 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), 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), see “- 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), see “Non-GAAP Financial Measures” below.

Table of Contents

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 and six months ended June 30, 2017 and 2016 (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Reconciliation of Segment Gross Margin to Net loss attributable to the Partnership:				
Gas Gathering and Processing Services segment gross margin	$12,651	$13,337	$23,902	$24,957
Liquid Pipelines and Services segment gross margin	6,683	9,432	13,152	15,284
Natural Gas Transportation Services segment gross margin	5,631	3,843	11,750	9,406
Offshore Pipelines and Services segment gross margin	25,623	20,558	51,426	33,819
Terminalling Services segment gross margin [1]	10,760	11,586	21,920	21,030
Propane Marketing Services segment gross margin	17,952	22,316	37,254	50,621
Total Segment Gross Margin	79,300	81,072	159,404	155,117
Less:				
Other direct operating expenses [1]	28,886	29,579	55,902	57,545
Plus:				
Gain (loss) on commodity derivatives, net	207	(1,367)	(50)	(1,605)
Less:				
Corporate expenses	30,084	22,281	62,928	43,382
Depreciation, amortization and accretion expense	30,170	26,398	59,521	51,439
(Gain) loss on sale of assets, net	52	478	(176)	1,600
Interest expense	17,152	10,610	35,118	18,912
Other income	(72)	(496)	(86)	(527)
Other (income) expense, net	136	(365)	806	(730)
Income tax expense	801	701	1,924	1,436
Loss from discontinued operations, net of tax	—	—	—	539
Net income attributable to noncontrolling interest	1,462	954	2,765	951
Net loss attributable to the Partnership	$(29,164)	$(10,435)	$(59,348)	$(21,035)

[1] Other direct operating expenses include Gas Gathering and Processing Services segment direct operating expenses of $8.0 million and $8.9 million for the three months ended June 30, 2017 and 2016, and $16.1 million and 17.5 million, for the six months ended June 30, 2017 and 2016, respectively, Liquid Pipelines and Services segment direct

operating expenses of $1.8 million and $2.2 million for the three months ended June 30, 2017 and 2016, and $3.9 million and $4.7 million for the six months ended June 30, 2017 and 2016, respectively, Natural Gas Transportation Services segment direct operating expenses of $1.9 million and $2.0 million for the three months ended June 30, 2017 and 2016, and $3.2 million and $3.2 million for the six months ended June 30, 2017 and 2016, respectively, Offshore Pipelines and Services segment direct operating expenses

Table of Contents

of $3.5 million and $2.8 million for the three months ended June 30, 2017 and 2016, and $6.1 million and $5.1 million for the six months ended June 30, 2017 and 2016, respectively, and Propane Marketing Services segment direct operating expenses of $13.6 million and $13.6 million for the three months ended June 30, 2017 and 2016, and $26.7 million and $27.1 million for the six months ended June 30, 2017 and 2016, respectively. Direct operating expenses related to our Terminalling Services segment of $3.0 million and $2.4 million for the three months ended June 30, 2017 and 2016, respectively, as well as $6.1 million and $5.0 million for the six months ended June 30, 2017 and 2016 are included within the calculation of Terminalling Services segment gross margin.

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Reconciliation of Net loss attributable to the Partnership to Adjusted EBITDA:				
Net loss attributable to the Partnership	$(29,164)	$(10,435)	$(59,348)	$(21,035)
Add:				
Depreciation, amortization and accretion expense	29,885	26,398	58,956	51,439
Interest expense	13,900	9,800	28,835	17,400
Debt issuance costs paid	714	1,152	2,116	1,475
Unrealized loss on derivatives, net	1,748	3,488	3,021	4,870
Non-cash equity compensation expense	1,195	1,408	5,233	3,051
Transaction expenses	12,067	3,089	20,685	4,162
Income tax expense	801	701	1,924	1,436
Discontinued operations	—	(8)	—	168
Distributions from unconsolidated affiliates	15,900	26,562	38,394	40,077
General Partner contribution for cost reimbursement	15,130	3,500	24,744	5,000
Deduct:				
Earnings in unconsolidated affiliates	17,552	11,702	32,954	19,045
Other income (loss)	126	(24)	154	(47)
OPEB plan net periodic benefit	10	(8)	10	(8)
Gain (loss) on sale of assets, net	(52)	(478)	176	(1,600)
Adjusted EBITDA	$44,540	$54,463	$91,266	$90,653

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 — Consolidated

Net loss attributable to the Partnership increased by $18.7 million for the three months ended June 30, 2017, and increased by $38.2 million, for the six months ended June 30, 2017 as compared to the same periods in 2016.

For the three months ended June 30, 2017, direct operating expenses decreased by $0.1 million primarily due to lower compressor rental costs. Corporate expenses increased by $7.8 million, or 35.0%, due to an increase of $3.0 million of merger-related costs which include legal, consulting services and employee severance costs; $3.0 million relating to a settlement of litigation claim; $1.1 million transition expenses related to affiliate assets; $0.8 million of share of legal costs related to right-of-way agreements; and $0.3 million due to increased office expense, partially offset by capitalized labor of $1.1 million associated with our capital project to upgrade our accounting system and management fee income of $0.8 million. Interest expense increased by $6.5 million, or 61.7%, as a result of additional borrowings to fund capital growth and acquisitions. Earnings from unconsolidated affiliates increased by $5.9 million, or 50.4%, as result of our investments in the Emerald Transactions and the additional investments in Delta House occurring in Q2 and Q4 2016.

Table of Contents

For the six months ended June 30, 2017, direct operating expenses decreased by $0.6 million primarily due to lower compressor rental costs. Corporate expenses increased by $19.5 million, or 45.1%, due to an increase of $8.4 million of merger-related costs which include legal, consulting services and employee severance costs; $3.0 million relating to a settlement of litigation claim; $2.3 million of transition expenses related to affiliate assets; $1.5 million of labor costs mainly due to increased headcount and severance expense; $1.4 million of compensation relating to severance costs, $1.0 million of our share of legal costs related to right-of-way agreements; and higher contract labor costs and insurance premiums on offshore assets. Interest expense increased by $16.2 million, or 85.7%, as a result of $14.0 million increase of interest expense and additional borrowings to fund capital growth and acquisitions. Earnings from unconsolidated affiliates increased by $14.0 million, or 73.7%, as result of our investments 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 June 30, 2017 was $79.3 million and $159.4 million for the six months ended June 30, 2017 compared to $81.1 million for the three months ended June 30, 2016 and $155.1 million for the six months ended June 30, 2016. This decrease of $1.8 million for the three months ended June 30, 2017 was primarily due to our Propane Marketing Services segment's gross margin decrease of $4.3 million due to lower NGL sales as a result of lower oilfield services, expiration of short term marketing deals that expired in 2016 on crude oil supply logistics ("COSL") for $2.7 million in our Liquid Pipelines and Services segment, partially offset by an increase in our Offshore Pipelines and Services segment of $5.1 million as a result of higher earnings in unconsolidated affiliates. For the six months ended June 30, 2017, the increase of $4.3 million was primarily due to higher segment gross margin in our Offshore Pipelines and Services segment of $17.6 million as a result of increased earnings in unconsolidated affiliates and the American Panther system that was acquired in Q2 2016, and an increase in our Natural Gas Transportation Services segment of $2.3 million mostly due to higher throughput as a result of new firm transportation contracts on our AlaTenn, MLGT, and Midla systems. These increases were partially offset by a decrease of $13.3 million related to our Propane Marketing Services segment primarily attributable to lower NGL sales as a result of the warmer winter temperatures and lower oilfield services.

For the three months ended June 30, 2017, Adjusted EBITDA decreased $9.9 million, or 18.2%, compared to the same period in 2016. The decrease is primarily related to lower distributions from our unconsolidated affiliates of $10.7 million and a larger net loss for the quarter. For the six months ended June 30, 2017, Adjusted EBITDA increased $0.6 million, or 0.7%, compared to the same period in 2016. The increase is primarily related to support from our General Partner for cost reimbursement and partially offset by higher earnings from our unconsolidated affiliates.

We distributed $21.4 million to holders of our common units, or $0.4125 per common unit, during the three months ended June 30, 2017, and $46.3 million, or $0.8250 per common unit, during the six months ended June 30, 2017.

Table of Contents

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Statement of Operations Data:				
Revenue:				
Commodity sales	$153,728	$148,592	$312,229	$256,162
Services	39,698	38,611	81,086	74,655
Gain (loss) on commodity derivatives, net	207	(1,367)	(50)	(1,605)
Total revenue	193,633	185,836	393,265	329,212
Operating expenses:				
Costs of sales	128,816	115,080	261,601	189,018
Direct operating expenses	31,884	31,967	61,972	62,542
Corporate expenses	30,084	22,281	62,928	43,382
Depreciation, amortization and accretion	30,170	26,398	59,521	51,439
Total operating expenses	220,954	195,726	446,022	346,381
(Gain) loss on sale of assets, net	52	478	(176)	1,600
Operating loss	(27,373)	(10,368)	(52,581)	(18,769)
Other income (expense), net				
Interest expense	(17,152)	(10,610)	(35,118)	(18,912)
Other income	72	496	86	527
Earnings in unconsolidated affiliates	17,552	11,702	32,954	19,045
Loss from continuing operations before taxes	(26,901)	(8,780)	(54,659)	(18,109)
Income tax expense	(801)	(701)	(1,924)	(1,436)
Loss from continuing operations	(27,702)	(9,481)	(56,583)	(19,545)
Loss from discontinued operations, net of tax	—	—	—	(539)
Net loss	(27,702)	(9,481)	(56,583)	(20,084)
Less: Net income attributable to noncontrolling interests	1,462	954	2,765	951
Net loss attributable to the Partnership	$(29,164)	$(10,435)	$(59,348)	$(21,035)
Other Financial Data:				
Gross margin (1)	$79,300	$81,072	$159,404	$155,117
Adjusted EBITDA (1)	$44,540	$54,463	$91,266	$90,653

(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, see the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Total Revenue. Our total revenue for the three months ended June 30, 2017 was $193.6 million compared to $185.8 million for the three months ended June 30, 2016. This increase of $7.8 million was primarily due to the following:

- an increase in our Gas Gathering and Processing segment revenue of $9.3 million primarily due to a new contract at our Longview plant for NGLs, natural gas and condensate for $11.9 million, partially offset by a decrease in natural gas and condensate volumes at Chatom/Bazor Ridge for $1.5 million due to lower system volumes, and due to a marketing contract that ended in Q4 of 2016 for $0.8 million;
-

a decrease in our Liquid Pipelines and Services segment revenue of $1.6 million mostly due to the expiration of short term marketing deals on COSL that expired in Q2 2016 of $12.6 million partially offset by $9.3 million of increased crude oil sales contracts;

- an increase in our Natural Gas Transportation Services segment revenue of $3.5 million primarily due to an increase on the Magnolia system of $1.6 million due to favorable pricing and additional revenues on our MLGT and Midla system for $1.2 million due to new firm transportation contracts;
- an increase in our Offshore Pipelines and Services segment revenue of $1.5 million due primarily to higher volumes and management fees from our acquired American Panther system for $1.0 million;
- a decrease in our Terminalling Services segment revenue of $1.7 million mostly due to a decrease in sales of butane blending volumes due to timing of $2.6 million partially offset by a $0.7 million increase due to an expansion at our Harvey terminal; and
- a decrease in our Propane Marketing Services segment revenue of $2.7 million due to a reduction of NGL revenues due to lower propane sales resulting from lower volumes driven by continued overall warmer than normal temperatures during the winter and a decline in oilfield services.

Cost of Sales. Our purchases of natural gas, NGLs, condensate and crude for the three months ended June 30, 2017 was $128.8 million compared to $115.1 million for the three months ended June 30, 2016. This increase of $13.7 million was mostly due to higher NGL, natural gas and condensate purchases of $9.2 million due to an increase in throughput at the Longview Plant, increase of $1.2 million due to additional throughput on the Gloria and Lafitte system and increased propane prices of $2.0 million compared to the same period last year.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017 was $79.3 million compared to $81.1 million for the three months ended June 30, 2016. This decrease of $1.8 million was primarily due to our Propane Marketing Services segment of $4.4 million due to lower propane sales as a result of a decline in oilfield services, expiration of short term deals that expired in Q2 2016 on COSL for $2.7 million partially offset by our Offshore Pipelines and Services segment of $5.1 million as a result of increased earnings in unconsolidated affiliates and the American Panther system that was acquired in Q2 2016.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2017 were $31.9 million compared to $32.0 million for the three months ended June 30, 2016.

Corporate Expenses. Corporate expenses for the three months ended June 30, 2017 were $30.1 million compared to $22.3 million for the three months ended June 30, 2016. This increase of $7.8 million was primarily due to an increase of $3.0 million of merger related costs which include legal, consulting services and employee severance costs; $3.0 million relating to the settlement of a litigation claim; $1.1 million transition expenses related to affiliate assets; $0.8 million of share of legal costs related to right-of-way agreements; and $0.3 million related to higher office expense, which was partially offset by capitalized labor of $1.1 million and management fee income of $0.8 million.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the three months ended June 30, 2017 was $30.2 million compared to $26.4 million for the three months ended June 30, 2016. This increase of $3.8 million was primarily due to the decrease in useful life of certain customer lists for $3.0 million and incremental depreciation of fixed assets acquired over the last 12 months.

Interest Expense. Interest expense for the three months ended June 30, 2017 was $17.2 million compared to $10.6 million for the three months ended June 30, 2016. The increase year over year of $6.5 million was primarily due to interest charges on the 8.5% and 3.77% Senior Notes which were issued in the second half of 2016, and increased borrowings on our revolving credit facility to $678.0 million. This increase was partially offset by the write-off of remaining deferred financing fees associated with the JPE revolver in March 2017 due to the JPE revolver being paid off, which resulted in a reduced interest expense of $1.2 million.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the three months ended June 30, 2017 was $17.6 million compared to $11.7 million for the three months ended June 30, 2016. This increase of $5.9 million was primarily due to incremental earnings of $4.2 million related to our investment in Delta House and $1.6 million related to Destin and Okeanos, Emerald Transactions.

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Total Revenue. Our total revenue for the six months ended June 30, 2017 was $393.3 million compared to $329.2 million for the six months ended June 30, 2016. This increase of $64.1 million was primarily due to the following:

Table of Contents

- an increase in our Gas Gathering and Processing segment revenue of $20.5 million primarily due to increased revenue from sales of NGLs and condensate at the Longview Plant of $25.7 million due to three new contracts, two of which started in Q1 2017. This was partially offset by a decrease due to marketing contracts that ended in Q4 of 2016 for $3.1 million and reduced NGL and condensate volumes at Chatom/Bazor Ridge for $1.1 million due to lower system volumes;
- an increase in our Liquid Pipelines and Services segment revenue of $34.4 million due to an increase in revenue of $20.2 million due to more favorable pricing for COSL, an increase of $14.0 million due to additional crude oil sales contracts, and an increase of $1.2 million due to new wells coming on line on our Silver Dollar Pipeline;
- an increase in our Natural Gas Transportation Services segment revenue of $6.2 million primarily due to an increase on the Magnolia system of $3.5 million due to favorable prices and additional revenues on our AlaTenn, MLGT, and Midla systems for $1.9 million due to new firm transportation contracts;
- an increase in our Offshore Pipelines and Services segment revenue of $9.3 million due primarily to higher volumes and management fees from our acquired American Panther system for $6.7 million, and increased volumes sold to the Alliance Refinery on our Gloria system for $3.1 million;
- an increase in our Terminalling Services segment revenue of $2.7 million mostly due to an expansion at our Harvey terminal for $2.1 million; and
- a decrease in our Propane Marketing Services segment revenue of $10.6 million primarily due to a reduction in NGL revenues from lower propane sales driven by a decline in volumes associated with oilfield services and continued overall warmer than normal temperatures during winter.

Cost of Sales. Our purchases of natural gas, NGLs, condensate and crude for the six months ended June 30, 2017 was $261.6 million compared to $189.0 million for the six months ended June 30, 2016. This increase of $72.6 million was mostly due to higher NGL, natural gas and condensate purchases of $20.9 million due to an increase in throughput at the Longview Plant, increased crude oil prices and volumes in our Liquid Pipelines and Services segment driven by the favorable market conditions resulting in increased producer activity for $38.8 million and higher propane prices in our Propane Marketing Services segment for $4.4 million.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017 was $159.4 million compared to $155.1 million for the six months ended June 30, 2016. This increase of $4.3 million was primarily due to higher segment gross margin in our Offshore Pipelines and Services segment of $17.6 million as a result of increased earnings in unconsolidated affiliates and the American Panther system that was acquired in Q2 2016 and due to an increase in our Natural Gas Transportation Services segment of $2.4 million mostly due to an increase in throughput as a result of new firm transportation contracts on our AlaTenn, MLGT, and Midla systems. These increases were partially offset by a decrease of $13.3 million related to our Propane Marketing Services segment primarily attributable to the warmer winter temperatures and lower oilfield services.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2017 were $62.0 million compared to $62.5 million for the six months ended June 30, 2016. This decrease of $0.5 million was primarily due to decreased compressor rental expense of $0.7 million and other expenses.

Corporate Expenses. Corporate expenses for the six months ended June 30, 2017 were $62.9 million compared to $43.4 million for the six months ended June 30, 2016. This increase of $19.5 million was primarily due to an increase of $8.4 million of merger related costs which include legal, consulting services and employee severance costs; $3.0 million relating to the settlement of a litigation claim; $2.3 million of transition expenses related to affiliate assets; $1.5 million of labor costs mainly due to increased headcount and severance expense; $1.4 million of compensation relating to severance costs; $1.0 million of share of legal costs related to right-of-way agreements; $0.8 million in contract labor costs; $0.6 million higher insurance premiums on offshore assets; which was partially offset by capitalized labor of $1.1 million.

Depreciation, Amortization and Accretion Expense. Depreciation, amortization and accretion expense for the six months ended June 30, 2017 was $59.5 million compared to $51.4 million for the six months ended June 30, 2016. This increase of $8.1 million was primarily due to the decrease in useful life for certain customer lists for $5.3 million and incremental depreciation of fixed assets acquired in the last 12 months mainly related to our Midla project.

Interest Expense. Interest expense for the six months ended June 30, 2017 was $35.1 million compared to $18.9 million for the six months ended June 30, 2016. This increase of $16.2 million was primarily due to interest on the 8.5% and 3.77% Senior Notes issued in the second half of 2016 increasing interest expense $14.0 million, increased borrowing on the Credit agreement $3.0 million and $1.3 million in associated financing costs, partially offset with the reduced interest expense of $1.2 million related to the acceleration of deferred financing costs due to the settlement of the JPE debt in March 2017.

Table of Contents

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the six months ended June 30, 2017 was $33.0 million compared to $19.0 million for the six months ended June 30, 2016. This increase of $14.0 million was primarily due to incremental earnings of $7.8 million related to our investment in Delta House and earnings of $5.3 million from the interests in the entities underlying the Emerald Transactions which were acquired in April 2016, offset by a decrease of $0.8 million from our interests in Main Pass Oil Gathering Company ("MPOG").

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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Segment Financial and Operating Data:				
Gas Gathering and Processing Services segment				
Financial data:				
Commodity sales	$33,650	$24,274	$62,423	$41,277
Services	5,657	6,436	11,291	12,727
Revenue from operations	39,307	30,710	73,714	54,004
Loss on commodity derivatives, net	(98)	(763)	(105)	(866)
Segment revenue	39,209	29,947	73,609	53,138
Cost of sales	26,582	17,162	49,769	28,868
Direct operating expenses	8,045	8,945	16,110	17,492
Other financial data:				
Segment gross margin [(2)]	$12,651	$13,337	$23,902	$24,957
Operating data:				
Average throughput (MMcf/d)	209.0	216.4	208.0	221.0
Average plant inlet volume (MMcf/d) [(1)]	104.5	100.7	104.0	103.0
Average gross NGL production (Mgal/d) [(1)]	398.8	263.3	348.0	269.0
Average gross condensate production (Mgal/d) [(1)]	79.8	84.3	81.0	78.0

(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, see the information in this Item under the caption "How We Evaluate Our Operations."

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Commodity sales. Commodity sales revenue for the three months ended June 30, 2017 was $33.7 million compared to $24.3 million for the three months ended June 30, 2016. This increase of $9.4 million was primarily due to the following:

- increased revenue from sales of NGLs, natural gas and condensate at the Longview Plant of $11.9 million due to three new contracts, two of which started in Q1 2017. One of the new contracts from Q1 2017 was previously a service contract;
- partially offsetting this were marketing contracts that ended in Q4 of 2016 for $0.8 million; and
- reduced NGL, natural gas and condensate volumes at Chatom/Bazor Ridge for $1.7 million due to lower system volumes;

Services. Segment services revenue for the period ended June 30, 2017 was $5.7 million compared to $6.4 million for the three months ended June 30, 2016. The decrease is primarily due to a new contract that increased commodity sales but led to a decline in transportation and fractionation fees of $0.6 million on Longview and lower compression and gathering charges of $0.5 million on our Lavaca system.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2017 were $26.6 million compared to $17.2 million for the three months ended June 30, 2016. This increase of $9.4 million was primarily due to the increase

Table of Contents

of NGL, natural gas 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 new contracts.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017 was $12.7 million compared to $13.3 million for the three months ended June 30, 2016 for reasons discussed above.

Direct Operating Expenses. Direct operating expenses of $8.0 million for three months ended June 30, 2017 declined from $8.9 million for the three months ended June 30, 2016, mainly due to our ongoing cost savings initiatives reducing labor costs $0.5 million, $0.2 million of lower regulatory costs, $0.1 million due to the timing of chemical purchases and costs related to measurement equipment, partially offset by increased contract services costs of $0.2 million.

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Commodity sales. Commodity sales revenue for the six months ended June 30, 2017 was $62.4 million compared to $41.3 million for the six months ended June 30, 2016. This increase of $21.1 million was primarily due to the following:

- increased revenue from sales of NGLs and condensate at the Longview Plant of $25.7 million due to three new contracts, two of which started in Q1 2017. One of the new contracts from Q1 2017 had previously been a service contract;
- partially offsetting this was a decrease due to marketing contracts that ended in Q4 of 2016 for $3.1 million; and
- reduced NGL and condensate volumes at Chatom/Bazor Ridge for $2.1 million due to lower system volumes.

Services. Segment services revenue for the six months ended June 30, 2017 was $11.3 million compared to $12.7 million for the six months ended June 30, 2016. The decrease is primarily due to decline in compression and gathering charges by $1.5 million on our Lavaca system.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2017 were $49.8 million compared to $28.9 million for the six months ended June 30, 2016. This increase of $20.9 million was primarily due to the increase of NGL, natural gas and condensate sales at the Longview Plant, as mentioned above. Additionally, there was also an decrease in throughput on our rail and increased freight charges due to new contracts.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017 was $23.9 million compared to $25.0 million for the six months ended June 30, 2016 as discussed above.

Direct Operating Expenses. Direct operating expenses of $16.1 million for six months ended June 30, 2017 declined from $17.5 million for the six months ended June 30, 2016, mainly due to our ongoing cost savings initiatives reducing compressor rentals and labor costs by $0.7 million and $0.6 million, respectively. Additionally we had $0.2 million lower regulatory costs, partially offset by higher contract services of $0.4 million.

Table of Contents

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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Segment Financial and Operating Data:				
Liquid Pipelines and Services segment				
Financial data:				
Commodity sales	$79,566	$82,257	$158,511	$123,177
Services	2,737	3,158	5,831	6,753
Revenue from operations	82,303	85,415	164,342	129,930
Gain (loss) on commodity derivatives, net	297	(716)	669	(948)
Earnings in unconsolidated affiliates	1,482	1,009	2,569	1,009
Segment revenue	84,082	85,708	167,580	129,991
Cost of sales	77,332	76,992	154,409	115,645
Direct operating expenses	1,833	2,235	3,906	4,701
Other financial data:				
Segment gross margin [(1)]	$6,683	$9,432	$13,152	$15,284
Operating data:				
Average throughput Pipeline (Bbls/d)	32,957	31,090	33,020	31,418
Average throughput Truck (Bbls/d)	1,943	2,016	1,751	1,619

---

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

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Commodity Sales. Segment revenue from crude oil for the three months ended June 30, 2017 was $79.6 million compared to $82.3 million for the three months ended June 30, 2016. The decrease of $2.7 million was primarily due to the expiration of short term marketing deals on COSL that expired in Q2 2016 for $12.6 million partially offset by $9.3 million of increased marketing crude oil contracts.

Services revenue. Segment services revenue for the three months ended June 30, 2017 was $2.7 million compared to $3.2 million for the three months ended June 30, 2016. The decrease of $0.5 million was primarily due to a decline in crude oil transportation revenue due to lower volumes and price as well as declining trucking rates as a result of increased competition.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the three months ended June 30, 2017 was $1.5 million compared to $1.0 million for the three months ended June 30, 2016. The increase of $0.5 million was due to the additional month of earnings in second quarter 2017 versus 2016 as the interests in Tri-states and Wilprise were acquired in late April 2016.

Cost of Sales. Purchases of crude oil for the three months ended June 30, 2017 was $77.3 million compared to $77.0 million for the three months ended June 30, 2016 and remained relatively flat.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017, was $6.7 million compared to $9.4 million for the three months ended June 30, 2016. Segment margin decreased by $2.7 million due to the reasons discussed above.

Direct Operating Expenses. Direct operating expenses of $1.8 million for the three months ended June 30, 2017 declined from $2.2 million for the three months ended June 30, 2016 mainly due to a decrease of $0.3 million for equipment lease and measurement costs and $0.1 million lower property tax expense .

Table of Contents

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Commodity Sales. Segment revenue from crude oil for the six months ended June 30, 2017 was $158.5 million compared to $123.2 million for the six months ended June 30, 2016. The increase of $35.3 million was primarily due to an increase in revenue of $20.4 million due to favorable pricing for COSL, an increase of $14.0 million due to additional crude oil sales contracts, and an increase of $1.1 million due to new wells coming on line, on our Silver Dollar Pipeline.

Services revenue. Segment services revenue for the six months ended June 30, 2017 was $5.8 million compared to $6.8 million for the six months ended June 30, 2016. The decrease of $1.0 million was primarily due to tariff rate reductions of $0.6 million and the roll off in first quarter of Bakken system management fees.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the six months ended June 30, 2017 was $2.6 million compared to $1.0 million for the six months ended June 30, 2016, resulting from the acquisition of Tri-states and Wilprise in late April 2016.

Cost of Sales. Purchases of crude oil for the six months ended June 30, 2017 was $154.4 million compared to $115.6 million for the six months ended June 30, 2016. The increase of $38.8 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 of $24.2 million for COSL. Additionally, there was an increase of $13.3 million due to an additional crude oil sales contract added in Q1 2017.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017, was $13.2 million compared to $15.3 million for the six months ended June 30, 2016. Segment margin decreased by $2.1 million due to the reasons discussed above.

Direct Operating Expenses. Direct operating expenses of $3.9 million for the six months ended June 30, 2017 declined from $4.7 million for the six months ended June 30, 2016 mainly due to $0.3 million of lower property tax expense, $0.2 million equipment lease costs and $0.2 million for measurement equipment costs.

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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Segment Financial and Operating Data:				
Natural Gas Transportation Services segment				
Financial data:				
Commodity sales	$6,442	$4,226	$13,310	$8,875
Services	4,955	3,651	10,525	8,797
Segment revenue	11,397	7,877	23,835	17,672
Cost of sales	5,678	4,026	11,938	8,250
Direct operating expenses	1,928	1,963	3,163	3,190
Other financial data:				
Segment gross margin (1)	$5,631	$3,843	$11,750	$9,406

Operating data:				
Average throughput (MMcf/d)	407.0	388.0	398.0	433.0

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

Table of Contents

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the three months ended June 30, 2017 were $6.4 million compared to $4.2 million for the three months ended June 30, 2016. The increase of $2.2 million is primarily due to an increase on the Magnolia system of $1.6 million as a result of favorable prices in Q2 2017 and marketing increases for $0.4 million.

Services revenue. Segment services revenue for the three months ended June 30, 2017 was $5.0 million compared to $3.7 million for the three months ended June 30, 2016. This increase of $1.3 million was mostly due to new firm transportation contracts on our MLGT system.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2017 were $5.7 million as compared to $4.0 million for the three months ended June 30, 2016. This increase is primarily due to higher volumes and prices on Magnolia for $1.6 million.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017, was $5.6 million compared to $3.8 million for the three months ended June 30, 2016. This increase of $1.8 million was primarily due to reasons discussed above.

Direct Operating Expenses. Direct operating expenses remained flat at $1.9 million for the three months ended June 30, 2017 and 2016.

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the six months ended June 30, 2017 were $13.3 million compared to $8.9 million for the six months ended June 30, 2016. The increase of $4.4 million is primarily due to an increase on the Magnolia system of $3.5 million as a result of favorable prices in 2017 and marketing increases for $1.0 million.

Services revenue. Segment services revenue for the six months ended June 30, 2017 was $10.5 million compared to $8.8 million for the six months ended June 30, 2016. This increase of $1.7 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 six months ended June 30, 2017 were $11.9 million as compared to $8.3 million for the six months ended June 30, 2016 This increase is primarily due to higher prices on Magnolia for $3.2 million and marketing activity of $0.6 million.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017, was $11.8 million compared to $9.4 million for the six months ended June 30, 2016. This increase of $2.4 million was primarily due to reasons discussed above.

Direct Operating Expenses. Direct operating expenses remained flat at $3.2 million for the six months ended June 30, 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).

61

Table of Contents

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Segment Financial and Operating Data:				
Offshore Pipelines and Services segment				
Financial data:				
Commodity sales	$2,440	$1,815	$6,203	$3,820
Services	9,699	8,830	20,767	13,825
Revenue from operations	12,139	10,645	26,970	17,645
Earnings in unconsolidated affiliates	16,070	10,693	30,385	18,036
Segment revenue	28,209	21,338	57,355	35,681
Cost of sales	2,586	778	5,929	1,860
Direct operating expenses	3,490	2,802	6,070	5,055
Other financial data:				
Segment gross margin [(1)]	$25,623	$20,558	$51,426	$33,819
Operating data:				
Average throughput (MMcf/d)	322.0	493.0	363.0	462.0

[(1)] For the definition of segment gross margin and a discussion of how we use segment gross margin to evaluate our operating performance, see the information in this Item under the caption “How We Evaluate Our Operations.”
(2) These volumes exclude Equity Investment volumes.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the three months ended June 30, 2017 was $2.4 million compared to $1.8 million for the three months ended June 30, 2016. This increase of $0.6 million was primarily due to increased volumes sold to the Alliance Refinery on our Gloria system.

Services revenue. Segment services revenue for the three months ended June 30, 2017 was $9.7 million compared to $8.8 million for the three months ended June 30, 2016. This increase of $0.9 million was mostly due to higher management fees and volumes related to the addition of American Panther.

Earnings in unconsolidated affiliates. Earnings for the three months ended June 30, 2017 were $16.1 million compared to $10.7 million for the three months ended June 30, 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 that supply volumes to the offshore facility.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the three months ended June 30, 2017 were $2.6 million compared to $0.8 million for the three months ended June 30, 2016. This increase of $1.8 million was mainly due to additional throughput on our Gloria system for $1.0 million and $0.2 million attributable to additional throughput on the Lafitte system.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017 was $25.6 million compared to $20.6 million for the three months ended June 30, 2016. This increase of $5.0 million was primarily due to earnings in unconsolidated affiliates and from our American Panther system as noted above.

Direct Operating Expenses. Direct operating expenses were $3.5 million and $2.8 million on the three months ended June 30, 2017 and 2016, respectively . The increase of $0.7 million is mainly due to the addition of a Gulf of Mexico pipeline acquired in April 2016.

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Commodity Sales. Segment sales of natural gas, NGLs and condensate for the six months ended June 30, 2017 was $6.2 million compared to $3.8 million for the six months ended June 30, 2016. This increase of $2.4 million was primarily due to increased

Table of Contents

volumes sold to the Alliance Refinery on our Gloria system for $3.1 million partially offset by $1.0 million decrease on our HPGG system due to platform maintenance.

Services revenue. Segment services revenue for the six months ended June 30, 2017 was $20.8 million compared to $13.8 million for the six months ended June 30, 2016. This increase of $7.0 million was mostly due to higher management fees of $4.3 million and $2.4 million for our crude transportation volumes related to the acquisition of American Panther in April 2016.

Earnings in unconsolidated affiliates. Earnings for the six months ended June 30, 2017 were $30.4 million compared to $18.0 million for the six months ended June 30, 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 that supply volumes to the offshore facility.

Cost of Sales. Purchases of natural gas, NGLs and condensate for the six months ended June 30, 2017 were $5.9 million compared to $1.9 million for the six months ended June 30, 2016. This increase of $4.0 million was mainly due to additional throughput on our Gloria system.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017 was $51.4 million compared to $33.8 million for the six months ended June 30, 2016. This increase of $17.6 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 $6.1 million and $5.1 million for the six months ended June 30, 2017 and 2016. This increase of $1.0 million is mainly due to the addition of Gulf of Mexico pipeline acquired in April 2016.

Terminalling Services Segment

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Segment Financial and Operating Data:				
Terminalling Services segment				
Financial data:				
Commodity sales	$2,378	$5,037	$7,550	$7,739
Services	13,453	12,778	26,907	24,471
Revenue from operations	15,831	17,815	34,457	32,210
Loss on commodity derivatives, net	—	(260)	—	(436)
Segment revenue	15,831	17,555	34,457	31,774
Cost of sales	2,073	3,542	6,466	5,747
Direct operating expenses	2,998	2,388	6,071	4,997
Other financial data:				
Segment gross margin (2)	$10,760	$11,586	$21,920	$21,030
Operating data:				
Contracted capacity (Bbls)	5,139,367	5,018,233	5,219,517	4,768,767
Design capacity (Bbls) (3)	5,400,800	5,150,800	5,400,800	4,975,800
Storage utilization (1)	95.2 %	97.4 %	96.6 %	95.8 %

Terminalling and Storage throughput (Bbls/d)	60,711	59,306	116,990	118,597

(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, see the information in this Item under the caption “How We Evaluate Our Operations.”
(3) Excludes Caddo Mills and North Little Rock.

Table of Contents

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Commodity Sales. Segment commodity sales for the three months ended June 30, 2017 was $2.4 million compared to $5.0 million for the three months ended June 30, 2016. The decrease of $2.6 million relates to our refined products and is driven by the timing of our sale of butane blending volumes.

Services Revenue. Segment services revenue for the three months ended June 30, 2017 was $13.5 million compared to $12.8 million for the three months ended June 30, 2016. This increase is primarily driven by the increase in contracted capacity as a result of the expansion efforts at the Harvey terminal which started in 2015.

Cost of Sales. Segment purchases of NGLs for the three months ended June 30, 2017 was $2.1 million compared to $3.5 million for the three months ended June 30, 2016. The decrease of $1.4 million is due to the decrease in sales of our butane blending volumes.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017 was $10.8 million compared to $11.6 million for the three months ended June 30, 2016. The $0.8 million decrease in segment gross margin is mostly driven by the decrease in sale of butane blending volumes as noted above.

Direct Operating Expenses. Segment direct operating expense for the three months ended June 30, 2017 was $3.0 million compared to $2.4 million for the three months ended June 30, 2016. This increase was mainly driven by higher operating costs related to our Harvey expansion.

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Commodity Sales. Segment commodity sales for the six months ended June 30, 2017 was $7.5 million compared to $7.7 million for the six months ended June 30, 2016. The small decrease of $0.2 million relates to our refined products and is driven by a decrease in butane blending volumes.

Services Revenue. Segment services revenue for the six months ended June 30, 2017 was $26.9 million compared to $24.5 million for the six months ended June 30, 2016. The $2.4 million increase is primarily driven by a $2.1 million increase in contracted capacity and related ancillary services as a result of the expansion efforts at the Harvey terminal.

Cost of Sales. Segment purchases of NGLs for the six months ended June 30, 2017 was $6.5 million compared to $5.7 million for the six months ended June 30, 2016. The increase of $0.8 million is primarily due to the higher butane costs related to volumes sold.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017 was $21.9 million compared to $21.0 million for the six months ended June 30, 2016. The $0.9 million increase in segment gross margin is mostly driven by the Harvey storage expansion as noted above.

Direct Operating Expenses. Segment direct operating expense for the six months ended June 30, 2017 was $6.1 million compared to $5.0 million for the six months ended June 30, 2016. This increase was mainly driven by higher 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).

64

Table of Contents

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Segment Financial and Operating Data:				
Propane Marketing Services segment				
Financial data:				
Commodity sales	$29,252	$30,984	$64,232	$71,274
Services	3,197	3,757	5,765	8,082
Revenue from operations	32,449	34,741	69,997	79,356
Gain (loss) on commodity derivatives, net	8	374	(614)	647
Segment revenue	32,457	35,115	69,383	80,003
Cost of sales	14,565	12,580	33,090	28,648
Direct operating expenses	13,590	13,634	26,652	27,107
Other financial data:				
Segment gross margin (1)	$17,952	$22,316	$37,254	$50,621
Operating data:				
NGL and refined product sales (Mgal/d)	151.6	164.3	176.7	201.7

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

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Commodity Sales. Segment sales of NGLs for the three months ended June 30, 2017 were $29.3 million compared to $31.0 million for the three months ended June 30, 2016. This decrease of $1.7 million was due to a reduction of NGL revenues due to lower NGL sales resulting from lower volumes driven by continued overall warmer than normal temperatures and a decline in oilfield services.

Services Revenue. Services revenue for the three months ended June 30, 2017 was $3.2 million compared to $3.8 million for the three months ended June 30, 2016. This decrease of $0.6 million was due to the same business drivers as described in the "Commodity Sales" section above.

Cost of Sales. Segment purchases of NGLs for the three months ended June 30, 2017 was $14.6 million compared to $12.6 million for the three months ended June 30, 2016. The increase is due to higher propane prices in the three months ended June 30, 2017 compared to the same period in the prior year partially offset by lower sales volumes.

Segment Gross Margin. Segment gross margin for the three months ended June 30, 2017 was $18.0 million compared to $22.3 million for the three months ended June 30, 2016. The decrease of $4.3 million is driven by the reduced sales revenue and higher propane prices.

Direct Operating Expenses. Segment direct operating expenses for the three months ended June 30, 2017 was $13.6 million comparable to $13.6 million for the three months ended June 30, 2016.

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016

Commodity Sales. Segment sales of NGLs for the six months ended June 30, 2017 were $64.2 million compared to $71.3 million for the six months ended June 30, 2016. This decrease of $7.1 million was due to a reduction of NGL revenues due to lower NGL sales 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 six months ended June 30, 2017 was $5.8 million compared to $8.1 million for the six months ended June 30, 2016. This decrease of $2.3 million was due to the same business drivers as described in the ‘Commodity Sales’ section above.

Table of Contents

Cost of Sales. Segment purchases of NGLs for the six months ended June 30, 2017 was $33.1 million compared to $28.6 million for the six months ended June 30, 2016. The increase is due to higher propane prices in the six months ended June 30, 2017 compared to the same period in the prior year offset by lower sales volumes.

Segment Gross Margin. Segment gross margin for the six months ended June 30, 2017 was $37.3 million compared to $50.6 million for the six months ended June 30, 2016. The decrease of $13.3 million is driven by the reduced sales revenue and higher propane prices.

Direct Operating Expenses. Segment direct operating expenses for the six months ended June 30, 2017 was $26.7 million compared to $27.1 million for the six months ended June 30, 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 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, as well as sale of non-core assets. Changes in natural gas, crude oil, NGL and condensate prices and the terms of our contracts may have a direct impact on our generation and use of cash from operations due to their impact on net income (loss), along with the resulting changes in working capital. In the past, we mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, see the information provided under Part II, Item 7A of 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 June 30, 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 June 30, 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 Revolving Credit Facility

On March 8, 2017, we entered into the Second Amended and Restated Credit Agreement, with Bank of America N.A., as Administrative Agent, Collateral Agent and L/C Issuer, Wells Fargo Bank, National Association, as Syndication Agent, and other lenders or Credit Agreement, which increased our borrowing capacity from $750.0 million to $900.0 million and provided for an accordion feature that will permit, subject to customary conditions, the borrowing capacity under the facility to be increased to a

Table of Contents

maximum of $1.1 billion. The $900 million in lending commitments under the 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 the Credit Agreement from $50 million. 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 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 our assets and the assets of all, subject to certain exceptions, existing and future subsidiaries and all of the capital stock of our existing and future subsidiaries. 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 Note Purchase Agreement (as defined below), 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 six months ended June 30, 2017 and 2016, the weighted average interest rate on borrowings under our Credit Agreement and the JPE Revolver (as defined below) was approximately 4.67% and 4.15%, respectively. At June 30, 2017 and December 31, 2016, letters of credit outstanding under the Credit Agreement were $32.3 million and $7.4 million, respectively. As of June 30, 2017, we had approximately $678.0 million of borrowings and $32.3 million of letters of credit outstanding under the Credit Agreement resulting in $189.6 million of available borrowing capacity.

As of June 30, 2017, our consolidated total leverage ratio was 4.79 and our interest coverage ratio was 5.04, 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. See Note 12 - Debt Obligations to our condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report for further discussion of the Credit Agreement.

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.

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 six months ended June 30, 2017 and 2016, the weighted average interest rate on borrowings under our Credit Agreement and the JPE Revolver was approximately 4.67% and 4.15%, respectively.

Table of Contents

8.50% Senior Unsecured Notes

On December 28, 2016, the Issuers completed the issuance and sale of the 8.50% Senior Notes. The 8.50% Senior Notes rank equal in right of payment with all existing and future senior indebtedness of the Issuers, and senior in right of payment to any future subordinated indebtedness of the Issuers. The 8.50% Senior Notes were issued at par and provided approximately $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 is included in Restricted cash-long term on our consolidated balance sheet as of December 31, 2016. We also incurred $2.7 million of debt issuance costs resulting in net proceeds related to the 8.50% Senior Notes of $291.3 million. The 8.50% Senior notes were offered and sold to qualified institutional buyers in the United States pursuant to Rule 144A under the Securities Act, and to persons, other than U.S. persons, outside the United States pursuant to Regulation S under the Securities Act.

Upon the closing of the JPE Acquisition and the satisfaction of other conditions related thereto, the proceeds were used to repay and terminate the JPE Revolver and reduce borrowings under our Credit Agreement.

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. See Note 12 - Debt Obligations to our condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report for further discussion of the 8.50% Senior Notes.

3.77% Senior Secured Notes

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

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

Net proceeds from the 3.77% Senior Notes are restricted and 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. See Note 12 - Debt Obligations to our condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report on further discussion of the 3.77% Senior Notes.

Acquisition Support and Reimbursement

In recognition of the historically warm weather that adversely impacted the Propane Marketing Services segment and the transition-related impacts of the JPE Acquisition during the quarter, affiliates of ArcLight, the owner of our general partner agreed to absorb $9.6 million corporate overhead expenses, which were incurred by us in the first quarter of 2017 and subsequently paid the amount in the second quarter of 2017. 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

Table of Contents

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 $9.5 million at June 30, 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):

	Six months ended June 30,	
	2017	2016
Net cash provided by (used in):		
Operating activities	$25,276	$49,716
Investing activities	232,315	(141,976)
Financing activities	(257,354)	92,314
Net cash increase in cash and cash equivalents	$237	$54

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

Operating Activities. During the six months ended June 30, 2017, we had $25.3 million of cash provided by operating activities, a decrease of $24.4 million when compared to $49.7 million of cash provided by operating activities in the same period in 2016. The decrease in cash flows from operating activities resulted primarily from an increase of our net loss year over year by $36.5 million driven primarily by our transition costs, interest expense and merger-related expenses, offset by changes in non-cash add backs of approximately $10.0 million, primarily in depreciation, amortization and accretion, amortization of deferred financing costs and bad debt expenses.

Investing Activities. During the six months ended June 30, 2017, net cash provided by investing activities was $232.3 million, an increase of $374.3 million as compared to net cash used in investing activities of $142.0 million in the same period of 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 recorded since the end of 2016 and held in escrow and acquisitions of $100.9 million of investments in unconsolidated affiliates in the six months ended June 30, 2016, with no such comparable activity related to acquisitions in the same period in 2017.

Financing Activities. During the six months ended June 30, 2017, net cash used in financing activities was $257.4 million, a decrease of $349.7 million as compared to net cash provided by financing activities of $92.3 million in the same period in 2016. The decrease in cash flows from financing activities resulted primarily from a decrease of $71.5 million in borrowings on the revolving credit facility, an increase of $282.0 million in repayments on the revolving credit facility and an increase of $6.5 million in distributions made to unitholders. Partially offsetting these items was an increase in contributions from unitholders of $21.3 million.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At June 30, 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 June 30, 2017, our off-balance sheet arrangements totaled $37.6 million.

Capital Requirements

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

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

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

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the three months ended June 30, 2017, capital expenditures totaled $24.1 million, including expansion capital expenditures of $21.6 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 $0.4 million. For the six months ended June 30, 2017, capital expenditures totaled $44.3 million, including expansion capital expenditures of $37.7 million, maintenance capital expenditures of $4.2 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 $2.5 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 July 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 June 30, 2017, or $1.65 per common unit on an annualized basis. The cash distribution is expected to be paid on August 14, 2017, to unitholders of record as of the close of business on August 7, 2017.

Critical Accounting Policies

There were no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K 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, refer to Note 2 - New Accounting Pronouncements 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 6 - Risk Management Activities 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 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

Table of Contents

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)	Effect of Hypothetical +/-10% change
Propane Fixed Price (gallons)	July 1, 2017 - December 31, 2019	10,892,201	$(526)	$632
Crude Oil Fixed Price (barrels)	July 1,2017 - July 31, 2017	68,000	$160	$—

Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of terms 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 (loss). 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 June 30, 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.

Table of Contents

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 June 30, 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 June 30, 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.

Table of Contents

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	Amendment No. 4 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated May 25, 2017 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on May 31, 2017).
3.7	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).
3.8	Amendment No. 5 to Fifth Amended and Restated Agreement of Limited Partnership of American Midstream Partners, LP, dated June 30, 2017 (filed as Exhibit 3.1 to the Current Report on Form 8-K (Commission File No. 001-35257) filed on July 14, 2017).
3.9	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).
3.10	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).
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 June 30, 2017 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 June 30, 2017 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 June 30, 2017 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 June 30, 2017 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.

Table of Contents

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: August 9, 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)

Table of Contents

Exhibit Index

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	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).
3.8	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).
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 June 30, 2017 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 June 30, 2017 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 June 30, 2017 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 June 30, 2017 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.