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

FORM 8-K/A

(Amendment No. 1)

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **December 6, 2017**

AMERICAN MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**001-35257**	**27-0855785**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

2103 CityWest Blvd, Bldg 4, Suite 800, Houston, TX 77042 (Address of principal executive offices)	**80202** (Zip Code)

Registrant's telephone number, including area code: **(346) 241-3545**

Not applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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. ☐

Explanatory Note

This Amendment to Current Report on Form 8-K/A (this "Amendment") is being filed by American Midstream Partners, LP ("AMID") to amend and restate in their entirety Exhibits 99.1 and 99.2 to AMID's Current Report on Form 8-K dated December 6, 2017 (the "Original Report"). Exhibits 99.1 and 99.2 to the Original Report are superseded in their entirety by Exhibits 99.1 and 99.2 to this Amendment. The Original Report contained an inadvertent error in the calculation of the non-GAAP supplemental financial measure Adjusted EBITDA related to the omission of an adjustment for discontinued operations, which requires revisions to the corresponding line item in Exhibit 99.1 to the Original Report and in the presentation of such measure and the reconciliation of such measure to the most comparable GAAP measure in Exhibit 99.2 to the Original Report. AMID has also corrected certain typographical errors. No other information presented in the Original Report, including net income (the GAAP measure most directly comparable to Adjusted EBITDA), has changed. The consolidated financial statements of AMID filed as Exhibit 99.3 to the Original Report were not impacted. This Current Report also provides certain disclosure in compliance with Regulation FD.

Forward-Looking Statements

This Current Report, including its exhibits, includes forward-looking statements. These statements relate to, among other things, projections of 2017 and 2018 financial performance, strategic plans and growth projects. We have used the words "anticipate," "believe," "could," "estimate," "expect," "guidance," "intend," "may," "plan," "predict," "project," "should," "will," "potential," and similar terms and phrases to identify forward-looking statements. Although we believe the assumptions upon which these forward-looking statements are based are reasonable, any of these assumptions could prove to be inaccurate and the forward-looking statements based on these assumptions could be incorrect. 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. Actual results and trends in the future may differ materially from those suggested or implied by the forward-looking statements depending on a variety of factors which are described in greater detail in our filings with the U.S. Securities and Exchange Commission ("SEC"). See "Risk Factors" and other disclosures included in our Annual Report on Form 10-K for the year ended December 31, 2016, as filed with the SEC on March 28, 2017 and in our other filings with the SEC. All future written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the previous statements. The forward-looking statements herein speak as of the date of this Current Report. We undertake no obligation to update any information contained herein or to publicly release the results of any revisions to any forward-looking statements that may be made to reflect events or circumstances that occur, or that we become aware of, after the date hereof.

Item 7.01 Regulation FD Disclosure.

AMID expects to continue its strategy of creating commercial and operational density within its core areas, whereby AMID may conduct additional acquisitions or divestitures. Due to completion of certain acquisitions later than expected, inherent timing uncertainties of divestitures, and the transitional nature of these activities, management believes AMID could have 2017 Adjusted EBITDA slightly below the lower-end of previously issued guidance. Based on anticipated outcomes of AMID's growth strategy and other opportunities it is pursuing, management expects a material increase in 2018 Adjusted EBITDA.

The information provided in this Item 7.01 (including the exhibits referenced therein) shall be deemed "furnished" and shall not be deemed "filed" for the purposes of Section 18 of the Exchange Act, nor shall it be incorporated by reference in any filing made by AMID pursuant to the Securities Act of 1933, except to the extent that such filing incorporates by reference any or all of such information by express reference thereto.

Item 8.01 Other Events.

As further described in the Original Report, on September 1, 2017, AMID completed the disposition of its Propane Marketing Services business (the "Propane Business") to SHV Energy N.V. As a result of the disposition of the Propane Business, AMID classified the results of operations of the Propane Business as discontinued operations. Accordingly, AMID has recast its financial statements to retrospectively reflect this change in classification of the Propane Business to discontinued operations for all periods presented.

Part II, Item 6, and Part II, Item 7, of AMID's Form 10-K for the year ended December 31, 2016 (the "2016 Form 10-K") as filed with the SEC on March 28, 2017, which were previously superseded by recast information filed on the Original Report and on a Current Report on Form 8-K on September 18, 2017, are hereby recast as follows:

- Selected Financial Data included herein as Exhibit 99.1 supersedes Exhibit 99.1 to the Original Report and to the Current Report on Form 8-K filed on September 18, 2017; and

- Management's Discussion and Analysis of Financial Condition and Results of Operations included herein as Exhibit 99.2 supersedes Exhibit 99.2 to the Original Report and to the Current Report on Form 8-K filed on September 18, 2017.

The 2016 Form 10-K, Part II, Item 8, has been recast by Exhibit 99.3 to the Original Report. Exhibit 99.3 to the Original Report is not impacted by this Amendment to the Original Report.

There have been no revisions or updates to the 2016 Form 10-K other than the revisions noted above. This Amendment should be read in conjunction with the 2016 Form 10-K and Exhibit 99.3 to the Original Report.

Item 9.01 Financial Statements and Exhibits.

(d) *Exhibits.*

Number	Description
99.1	Selected Financial Data
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations

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 hereunto duly authorized.

	American Midstream Partners, LP	
	By :	**American Midstream GP, LLC,** *its General Partner*
Date: December 12, 2017	By:	/s/ Eric Kalamaras
	Name:	Eric Kalamaras
	Title:	Senior Vice President and Chief Financial Officer

EXHIBIT 99.1

Item 6. Selected Historical Financial and Operating Data

The following table presents selected historical consolidated financial and operating data for the periods and as of the dates indicated. We derived this information from our historical consolidated financial statements and accompanying notes. This information should be read together with, and is qualified in its entirety, by reference to those consolidated financial statements and notes, which for the years 2016 , 2015 , and 2014 begin on F-1 included in Exhibit 99.3 to our Current Report on Form 8-K filed on December 7, 2017 and dated December 6, 2017(the "Recast Form 8-K dated December 6, 2017").

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

On September 1, 2017, the Partnership completed the disposition of JPE's propane marketing services business ("the Propane Business"). Through the transaction, we divested Pinnacle Propane's 40 service locations; Pinnacle Propane Express' cylinder exchange business and related logistic assets; and the Alliant Gas utility system. Prior to the sale, we moved the trucking business from the Propane Marketing Services segment to the Liquid Pipelines and Services segment for all periods presented. In connection with the transaction, the Partnership received $170.0 million in cash and recorded a gain on the sale of $46.5 million, net of $2.5 million transaction costs. As a result of the disposition of the Propane Business, the Partnership has classified the accounts and the results of operations of the Propane Business as discontinued operations.

For a detailed discussion of the following table, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Exhibit 99.2 to our Current Report on Form 8-K/A dated December 12, 2017.

EXHIBIT 99.1

	Years ended December 31,				
	2016 [1]	2015 [1]	2014 [1]	2013 [1]	2012 [6]
	(in thousands, except per unit and operating data)				
Statements of Operations Data:					
Revenues:					
Total operating revenue	$ 589,026	$ 750,304	$ 838,949	$ 436,021	$ 77,717
Operating expenses:					
Cost of sales	393,351	567,682	672,948	331,831	72,520
Direct operating expenses	71,544	71,729	58,048	33,962	5,080
Corporate expenses	89,438	65,327	60,465	51,193	10,747
Depreciation, amortization and accretion	90,882	81,335	57,818	43,458	4,790
Loss (gain) on sale of assets, net	688	2,860	4,087	(17)	2
Loss on impairment of property, plant and equipment	697	—	21,344	8,830	—
Loss on impairment of goodwill	2,654	148,488	—	—	—
Total operating expenses	649,254	937,421	874,710	469,257	93,139
Operating loss	(60,228)	(187,117)	(35,761)	(33,236)	(15,422)
Other income (expense):					
Interest expense	(21,433)	(20,077)	(16,497)	(15,418)	(3,167)
Other income (expense)	254	1,460	(1,096)	544	13
Loss on extinguishment of debt	—	—	(1,634)	—	(497)
Earnings in unconsolidated affiliates	40,158	8,201	348	—	—
Loss from continuing operations before income taxes	(41,249)	(197,533)	(54,640)	(48,110)	(19,073)
Income tax (expense) benefit	(2,580)	(1,885)	(856)	212	(185)
Loss from continuing operations	(43,829)	(199,418)	(55,496)	(47,898)	(19,258)
Discontinued operations:					
Income (loss) from discontinued operations	(4,715)	(423)	(24,071)	13,446	10,870
Net loss	(48,544)	(199,841)	(79,567)	(34,452)	(8,388)
Net income (loss) attributable to non-controlling interests	2,766	(13)	3,993	705	—
Net loss attributable to the Partnership	$ (51,310)	$ (199,828)	$ (83,560)	$ (35,157)	$ (8,388)
General Partner's Interest in net loss	$ (233)	$ (1,823)	$ (398)	$ (864)	$ —
Limited Partners' Interest in net loss	$ (51,077)	$ (198,005)	$ (83,162)	$ (34,293)	$ (8,388)
Limited Partners' net (loss) per common unit:					
Basic and diluted:					
Loss from continuing operations	$ (1.51)	$ (4.91)	$ (2.77)	$ (3.21)	$ (1.19)
Income (loss) from discontinued operations	(0.09)	(0.01)	(0.52)	(0.07)	0.61
Net loss	$ (1.60)	$ (4.92)	$ (3.29)	$ (3.28)	$ (0.58)
Weighted average number of common units outstanding:					
Basic and diluted (2)	51,176	45,050	27,524	18,931	12,069

Statement of Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$ 90,639	$ 86,978	$ 51,635	$ 29,500	$ (6,990)
Investing activities	(564,504)	(250,769)	(518,023)	(115,173)	(292,334)
Financing activities	477,544	161,954	466,577	79,156	304,991
Other Financial Data:					
Adjusted EBITDA (3)	$ 167,190	$ 100,721	$ 74,286	$ 63,707	$ 14,559
Total segment gross margin (4)	223,635	179,856	153,524	96,809	5,197
Cash distribution declared per common unit	3.01	3.17	1.85	1.75	—
Segment gross margin:					
Gathering and Processing	48,245	65,692	51,213	5,673	—
Liquid Pipelines and Services	31,556	26,399	25,038	5,420	3,465
Natural Gas Transportation Services	18,616	18,073	13,691	13,150	—
Offshore Pipeline and Services	82,346	33,613	29,089	36,318	—
Terminalling Services	42,872	36,079	34,493	36,248	1,732
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 5,666	$ 1,987	$ 3,824	$ 3,627	$ 10,099
Accounts receivable and unbilled revenue	67,625	61,016	116,676	129,724	59,721
Property, plant and equipment, net	1,066,608	981,321	887,045	537,304	103,954
Total assets	2,349,321	1,751,889	1,865,210	1,292,695	562,124
Current portion of long-term debt	5,438	2,758	3,141	3,141	2,694
Long-term debt	1,235,538	687,100	456,965	314,764	164,429
Operating Data:					
Gas Gathering and Processing Services:					
Average throughput (MMcf/d)	220.6	240.0	155.8	129.5	—
Average plant inlet volume (MMcf/d) (5)	102.1	120.9	89.1	125.7	—
Average gross NGL production (Mgal/d) (5)	192.9	231.1	64.2	50.4	—
Average gross condensate production (Mgal/d) (5)	82.9	97.1	70.8	45.5	—
Liquid Pipelines and Services:					
Average throughput Pipeline (Bbl/d)	32,257	34,946	20,868	13,738	—
Average throughput Truck (Bbl/d)	1,628	—	—	—	—
Natural Gas Transportation Services:					
Average throughput (MMcf/d)	389.9	364.1	373.3	364.9	—
Average firm transportation - capacity reservation (MMcf/d)	634.7	637.2	567.9	592.5	—
Average interruptible transportation - throughput (MMcf/d)	65.3	70.2	65.3	106.4	—
Offshore Pipelines and Services:					
Average throughput (MMcf/d)	466.4	442.8	524.6	498.9	—
Average gross condensate production (Mgal/d) (5)	3.6	2.7	4.4	1.2	—
Average firm transportation - capacity reservation (MMcf/d)	53.4	16.6	10.0	—	—
Average interruptible transportation - throughput (MMcf/d)	288.7	340.1	403.7	361.6	—

Terminalling Services:					
Storage Capacity (Bbls)	5,011,133	4,487,542	4,247,058	4,114,792	3,000,000
Design Capacity (Bbls)	5,173,717	4,688,950	4,363,817	4,165,600	3,000,000
Storage utilization	96.9%	95.7%	97.3%	99.0%	100.0%
Terminalling and Storage throughput (Bbls/d)	56,741	62,075	63,859	69,071	57,143

(1) The following transactions affect comparability between years: i) in October 2016 and April 2016 we acquired 6.2% and 1% non-operated interests in Delta House Class A Units,which we account for as equity method investments and are included in our Offshore Pipelines and Services segment; ii) in April 2016, we acquired membership interests in Destin (49.7%), Tri-States (16.7%), Okeanos (66.7%), and Wilprise (25.3%), which we account for as equity method investments and are included in our Liquid Pipelines and Services and Offshore Pipelines and Services segments; iii) in April 2016 we acquired a 60% interest in American Panther which we consolidate for financial reporting purposes and is included in our Offshore Pipelines and Services segment; iv) in September 2015, we acquired a non-operated 12.9% indirect interest in Delta House Class A Units, which we account for as an equity method investment and is included in our Offshore Pipelines and Services segment; v) in October 2014 and January 2014, we acquired the Costar and Lavaca systems, respectively, both of which are included in our Gas Gathering and Processing Services segment; vi) in June 2014, we completed the sale of our crude oil logistics operations which was included in our Liquids Pipelines and Services segment; vii) in December 2013, we acquired Blackwater, which is included in our Terminals segment; and viii) in April 2013, we acquired the High Point System, which is included in Transmission segment.

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

(3) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read "Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations" included in Exhibit 99.2 to our Current Report on Form 8-K/A dated December 12, 2017.

(4) For a definition of Total segment gross margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP and a discussion of how we use Total segment gross margin to evaluate our operating performance, please read "Item 7. Management's Discussion and Analysis — How We Evaluate Our Operations" included in Exhibit 99.2 to our Current Report on Form 8-K/A dated December 12, 2017 .

(5) Excludes volumes and gross production under our elective processing arrangements. For a description of our elective processing arrangements, please read "Item 7. Management's Discussion and Analysis — Our Operations - Gathering and Processing Segment" included in Exhibit 99.2 to our Current Report on Form 8-K/A dated December 12, 2017.

(6) The 2012 selected financial data represents JPE financial activity only, given the common control was April 15, 2013; as mentioned above.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the audited consolidated financial statements and the related notes thereto included elsewhere in Exhibit 99.3 to the Current Report on Form 8-K dated December 6, 2017 filed by American Midstream Partners, LP (along with its consolidated subsidiaries, "we," "us," "our," or the "Partnership") on December 7, 2017 (the "Recast Form 8-K dated December 6, 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 under the caption "Cautionary Statement About Forward-Looking Statements" included in our Current Report on Form 8-K (the "Recast Form 8-K") as of and for the year ended December 31, 2016 as filed with the U.S. Securities and Exchange Commission (the "SEC") on September 18, 2017.

On March 8, 2017, the Partnership completed the acquisition of JP Energy Partners, LP ("JPE"), an entity controlled by ArcLight affiliates, in a unit-for-unit exchange. In connection with the transaction, each JPE common or subordinated unit held by investors not affiliated with ArcLight was converted into the right to receive 0.5775 of a Partnership common unit, and each JPE common or subordinated unit held by ArcLight affiliates was converted into the right to receive 0.5225 of a Partnership common unit. The Partnership issued a total of 20.2 million of its common units to complete the acquisition, including 9.8 million common units to ArcLight affiliates. Based upon the closing price for our common units on March 8, 2017, the units issued in the exchange had an estimated fair value of $322.2 million.

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.

As both the Partnership and JPE were controlled by ArcLight, the acquisition represents a transaction among entities under common control and is accounted for as a common control transaction in a manner similar to a pooling of interests. Although the Partnership is the legal acquirer, JPE is considered to be the acquirer for accounting purposes as ArcLight obtained control of JPE before it obtained control the Partnership. The accompanying financial statements represent the JPE historical cost basis financial statements, recast to reflect its acquisition of the Partnership at ArcLight's historical cost basis effective April 15, 2013, the date on which ArcLight obtained control of the Partnership. See Item 8. Financial Statements and Supplementary Data - Note 2 in Exhibit 99.3 to the Recast Form 8-K dated December 6, 2017 for more information on the JPE Merger.

On September 1, 2017, the Partnership completed the disposition of JPE's propane marketing services business (the "Propane Business"). Through the transaction, we divested Pinnacle Propane's 40 service locations; Pinnacle Propane Express' cylinder exchange business and related logistic assets; and the Alliant Gas utility system. Prior to the sale, we moved the trucking business from the Propane Marketing Services segment to the Liquid Pipelines and Services segment for all periods presented. In connection with the transaction, the Partnership received $170.0 million in cash and recorded a gain on the sale of $46.5 million, net of $2.5 million transaction costs. As a result of the disposition of the Propane Business, the Partnership has classified the accounts and the results of operations of the Propane Business as discontinued operations.

As previously reported in Part II, Item 9A of our 2016 Form 10-K management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2016, based on criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation of internal control over financial reporting, management concluded that as of December 31, 2016, the Partnership did not maintain a sufficient complement of resources with an appropriate level of accounting knowledge, expertise and training commensurate with its financial reporting requirements. Specifically, individuals within the Partnership's financial accounting and reporting functions did not have the appropriate level of expertise to ensure that complex, non-routine transactions of the Partnership were recorded appropriately. This control deficiency resulted in out-of-period adjustments recorded to the consolidated statement of operations in the fourth quarter of 2016 and a revision to the 2015 consolidated balance sheet and consolidated statement of cash flows. Management concluded that this deficiency in internal control over financial reporting could result in material misstatements of the Partnership's annual or interim consolidated financial statements that would not be prevented or detected on a timely basis. Accordingly, in connection with the assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2016, management concluded that this control deficiency constituted a material weakness. Because of this material weakness in internal control over financial reporting, management concluded that the Partnership's internal control over financial reporting was not effective as of December 31, 2016. Management has not undertaken, and is not required to have undertaken, an assessment of the effectiveness of the Partnership's internal control over financial reporting since the assessment of the Partnership's internal control over financial reporting as of December 31, 2016, as described above.

The controls of JPE were not part of the Partnership's internal control over financial reporting as of December 31, 2016. Accordingly, the controls operated at JPE were not included in either management's assessment of the Partnership's internal controls over financial reporting as of December 31, 2016 or in PricewaterhouseCoopers LLP's audit of such controls. Effective March 8, 2017, JPE is a wholly-owned subsidiary of the Partnership whose total assets and total revenue represented 28.7% and 68.0%, respectively, of the recast consolidated financial statement amounts as of and for the year ended December 31, 2016 included in Exhibit 99.3 to the Recast Form 8-K dated December 6, 2017.

Overview

We are a growth-oriented Delaware limited partnership that was formed in August 2009 to own, operate, develop and acquire a diversified portfolio of midstream energy assets. We provide critical midstream infrastructure that links producers of natural gas, crude oil, NGLs, condensate and specialty chemicals to numerous intermediate and end-use markets. Through our five financial reporting segments, (i) gas gathering and processing services, (ii) liquids pipelines and services, (iii) natural gas transportation services, (iv) offshore pipelines and services and (v) terminalling services, we engage in the business of gathering, treating, processing, and transporting natural gas; gathering, transporting, storing, treating and fractionating NGLs; gathering, storing and transporting crude oil and condensates; storing specialty chemical products; and selling 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 liquids pipelines, natural gas transportation and offshore pipelines and terminal assets are located in prolific producing regions and key demand markets in Alabama, Louisiana, Mississippi, North Dakota, Texas, Tennessee and in the Port of New Orleans in Louisiana and the Port of Brunswick in Georgia.

We own or have ownership interests in more than 3,800 miles of onshore and offshore natural gas, crude oil, NGL and saltwater pipelines across 16 gathering systems, six interstate pipelines and nine intrastate pipelines; eight natural gas processing plants; four fractionation facilities; an offshore semisubmersible floating production system with nameplate processing capacity of 80 MMBbl/d of crude oil and 200 MMcf/d of natural gas; and 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.

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

- Net loss attributable to the Partnership decreased by $148.5 million for the year ended December 31, 2016 as compared to the same period in 2015, primarily due to a decrease of $145.8 million in goodwill impairment charges, an increase in earnings in unconsolidated affiliates of $32.0 million primarily from our investments in Delta House and the entities underlying the Emerald Transactions, offset by an increase in corporate expense of $24.1 million due to our corporate relocation and JPE Merger expenses;

- Total segment gross margin increased by $43.8 million, or 24.3%, as compared to the same period in 2015 primarily attributable to an increase in our Offshore Pipelines and Services segment gross margin of $48.7 million as a result of increased revenues received by the Partnership due to the Pascagoula plant shutdown. The Pascagoula plant is not controlled or owned by the Partnership. As a result of the Pascagoula plant shutdown, volumes were redirected to our High Point system. Additionally, the incremental earnings from our equity method investees increased by $32.0 million, of which $29.9 million was attributable to our Offshore Pipelines and Services segment;

- Adjusted EBITDA increased by $66.4 million, or 66.0%, as compared to the same period in 2015 primarily due to distributions from our investments in Delta House and entities underlying the Emerald Transactions; and

- We distributed $112.1 million to our common unitholders;

- On February 1, 2016, we sold certain trucking and marketing assets in the Mid-Continent area (the "Mid-Continent Business"), in connection with JP Development's, an affiliated entity, sale of its GSPP pipeline assets to a third party buyer. The sales price related to the Mid-Continent Business was $9.7 million; which included certain adjustments related to inventory and working capital items. We recognized a loss on the disposal of approximately $12.9 million during the year ended December 31, 2015. Prior to the classification of discontinued operations, we reported the Mid-Continent Business in our Liquid Pipelines and Services segment. We continue to retain our crude oil storage operations in the Mid-Continent area of Oklahoma;

- On April 25, 2016 and April 27, 2016, we acquired a 16.7% interest in Tri-States, an NGL pipeline; a 66.7% interest in Okeanos, a natural gas pipeline, a 49.7% interest in Destin, a natural gas pipeline, and a 25.3% interest Wilprise, an NGL pipeline for $211.0 million. We funded the aggregate purchase price with the issuance of 8,571,429 Series C Convertible Preferred Units and a warrant to purchase up to 800,000 of our common units at an exercise price of $7.25 per common unit with a combined value of approximately $120.0 million , plus additional borrowings of $91.0 million under our revolving credit agreement;

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

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

- On October 23, 2016, we announced the acquisition of JPE. The transaction closed on March 8, 2017 and resulted in a larger and more diversified midstream business;

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

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

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

- The percentage of gross margin generated from fee-based, fixed-margin, firm and interruptible transportation contracts and firm storage contracts was 91.4% representing a 2.8% increase compared to 2015;

- Average gross condensate production totaled 86.6 Mgal/d, representing a 13.2 Mgal/d or 13.2% decrease compared to 2015 due to lower condensate prices of 10.9% and 22.1% in our Gas Gathering and Processing Services and Offshore Pipelines and Services segments, respectively;

- Throughput volumes attributable to the Partnership totaled 1,076.9 MMcf/d, representing a 2.9% increase compared to 2015 due to the Pascagoula plant shutdown, which redirected volumes to our High Point system;

- Pipelines throughput volumes attributable to our Liquid Pipelines and Services segment totaled 32,257 Bbls/d, representing a 14.2% increase compared to 2015 due to an increase in activity around our Silver Dollar Pipeline system;

- Contracted capacity for our Terminals segment averaged 5,011,233 barrels, representing a 11.7% increase compared to 2015 due to the expansion efforts at our Harvey terminal; and

- Average gross NGL production totaled 192.9 Mgal/d, representing a 38.2 Mgal/d or 16.5% decrease compared to 2015.

Our Operations

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

- ***Gas Gathering and Processing Services.*** Our Gas Gathering and Processing 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.

Gas Gathering and Processing Services Segment

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

- ***Fee-Based Arrangements.*** Under these arrangements, we generally are paid a fixed fee for gathering, processing and transporting natural gas and crude oil.

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

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

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

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.

Natural Gas Transportation Services Segment

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

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

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

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

Offshore Pipelines and Services Segment

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

- ***Firm Transportation Arrangements.*** Our obligation to provide firm transportation service means that 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 and truck weighing. Our firm storage contracts are typically multi-year contracts with renewal options.

How We Evaluate Our Operations

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

Throughput Volumes

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

In our Liquid Pipelines and Services segment, t he amount of revenue we generate from our crude oil pipelines business depends primarily on throughput volumes. We generate a portion of our crude oil pipeline revenues through long-term contracts containing acreage dedications or minimum volume commitments. Throughput volumes on our pipeline system are affected primarily by the supply of crude oil in the market served by our assets. The revenue generated from our crude oil supply and logistics business depends on the volume of crude oil we purchase from producers, aggregators and traders and then sell to producers, traders and refiners as well as the volumes of crude oil that we gather and transport. The volume of our crude oil supply and logistics activities and the volumes transported by our crude oil gathering and transportation trucks are affected by the supply of crude oil in the markets served directly or indirectly by our assets. Accordingly, we actively monitor producer activity in the areas served by our crude oil supply and logistics business and other producing areas in the United States to compete for volumes from crude oil producers. Revenues in this business are also impacted by changes in the market price of commodities that we pass through to our customers.

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

In our Terminalling Services segment, we generally receive fee-based compensation on guaranteed firm storage contracts, throughput fees charged to our customers when their products are either received or disbursed, and other operational charges associated with ancillary services provided to our customers, such as excess throughput, steam heating and truck weighing at our marine terminals. The amount of revenue we generate from our refined products terminals depends primarily on the volume of refined products that we handle. These volumes are affected primarily by the supple of and demand for refined products in the markets served directly or indirectly by our refined products terminals. The volume of crude oil stored at our crude oil storage facility in Cushing, Oklahoma has no impact on the revenue generated by our crude oil storage business because we receive a fixed monthly fee per barrel of shell capacity that is not contingent on the usage of our storage tanks.

Storage Utilization

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

Segment Gross Margin and Total Segment Gross Margin

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

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

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

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

We define segment gross margin in our Terminalling Services segment as total revenue less the cost of sales utilized in our blending and injection of additives less direct operating expense.

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

Operating Margin

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

Direct Operating Expenses

Our management seeks to maximize the profitability of our operations in part by minimizing direct operating expenses without sacrificing safety or the environment. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities, lost and unaccounted for gas, and contract services comprise most 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 depreciation, amortization and accretion expense, interest expense, debt issuance costs, unrealized losses on derivatives, non-cash charges such as non-cash equity compensation expense, and charges that are unusual such as transaction expenses primarily associated with our acquisitions (such as JPE, Delta House and Panther), income tax expense, distributions from unconsolidated affiliates and general partner's contribution, less earnings in unconsolidated affiliates, gains (losses) that are unusual, other, net, and gain on sale of assets, net.

We have changed our definition of Adjusted EBITDA to include the Adjusted EBITDA of our discontinued operations as we believe the impact to our operating results of our discontinued operations should be reflected in our Adjusted EBITDA for the historical periods we owned the businesses. We believe including the impact of our discontinued operations for the periods in which the businesses were owned is more meaningful to our investors and more reflective of the Partnership's actual performance. In connection with filing our Report on Form 10-Q for the quarter ended September 30, 2017, we had reported our Adjusted EBITDA without the Adjusted EBITDA of our discontinued operations.

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 loss attributable to the Partnership, please see "- Note About Non-GAAP Financial Measures" below.

Note about Non-GAAP Financial Measures

Total segment gross margin, operating margin and Adjusted EBITDA 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 measure. Management compensates for the limitations of these non-GAAP measure as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

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

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

	Years Ended December 31,		
	2016 (1)	2015 (1)	2014 (1)
		(In thousands)	
Reconciliation of Total Segment Gross Margin to Net loss attributable to the Partnership			
Gas Gathering and Processing Services	$ 48,245	$ 65,692	$ 51,213
Liquid Pipelines and Services	31,556	26,399	25,038
Natural Gas Transportation Services	18,616	18,073	13,691
Offshore Pipelines and Services	82,346	33,613	29,089
Terminalling Services	42,872	36,079	34,493
Total Segment Gross Margin	**223,635**	**179,856**	**153,524**
Less:			
Direct operating expenses (2)	60,762	61,315	46,523
Operating margin	**162,873**	**118,541**	**107,001**
Add:			
Gains (losses) on commodity derivatives, net	(1,617)	1,345	1,091
Deduct:			
Corporate expenses	89,438	65,327	60,465
Depreciation, amortization and accretion	90,882	81,335	57,818
Loss on sale of assets, net	688	2,860	4,087
Loss on impairment of property, plant and equipment	697	—	21,344
Loss on impairment of goodwill	2,654	148,488	—
Loss on extinguishment of debt	—	—	1,634
Interest expense	21,433	20,077	16,497
Other (income) expense	(254)	(1,460)	1,096
Other, net (3)	(3,033)	792	(209)
Income tax expense	2,580	1,885	856
Loss from discontinued operations	4,715	423	24,071
Net income (loss) attributable to noncontrolling interest	2,766	(13)	3,993
Net loss attributable to the Partnership	**$ (51,310)**	**$ (199,828)**	**$ (83,560)**

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

(2) Direct operating expenses includes Gas Gathering and Processing Services segment direct operating expenses of $33.8 million, $35.3 million, and $21.2 million, respectively, Liquid Pipelines and Services segment direct operating expenses of $10.1 million, $9.9 million, and $7.2 million, respectively, Natural Gas Transportation Services segment direct operating expenses of $5.9 million, $6.7 million, and $7.0 million, respectively and Offshore Pipelines and Services segment direct operating

expenses of $10.9 million, $9.4 million, and $11.1 million, respectively. Direct operating expenses exclude amounts related to the Terminalling segment as those costs are included in segment gross margin for Terminalling.

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

	Years Ended December 31,		
	2016	2015	2014
Reconciliation of Net loss attributable to the Partnership to Adjusted EBITDA:			
Net loss attributable to the Partnership	$ (51,310)	$ (199,828)	$ (83,560)
Add:			
Depreciation, amortization and accretion	90,882	81,335	57,818
Interest expense	18,197	17,686	13,379
Debt issuance costs paid	5,328	2,244	7,034
Unrealized (gain) loss on derivatives, net	(10,328)	495	(641)
Non-cash equity compensation expense	5,658	5,080	3,415
Corporate office relocation	9,096	—	—
Transaction expenses [1]	14,084	3,303	5,560
Income tax expense	2,580	1,885	856
Loss on impairment of property, plant and equipment	697	—	21,344
Loss on impairment of noncurrent assets held for sale	—	—	673
Loss on impairment of goodwill	2,654	148,488	—
Loss on extinguishment of debt	—	—	1,634
Distributions from unconsolidated affiliates	83,046	20,568	1,980
General Partner contribution for cost reimbursement	7,500	3,000	—
Deduct:			
Earnings in unconsolidated affiliates	40,158	8,201	348
Construction and operating management agreement income	1,465	841	943
Other post-employment benefits plan net periodic benefit	17	14	45
Loss on sale of assets, net	(688)	(2,860)	(4,087)
Net impact of discontinued operations [2]	30,058	22,661	42,043
Adjusted EBITDA	**$ 167,190**	**$ 100,721**	**$ 74,286**

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

[2] Amounts primarily represent adjustments related to depreciation, amortization and accretion, unrealized (gain) loss on derivatives, (gain) loss on asset sales and goodwill impairment related to our discontinued operations.

General Trends and Outlook

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

We anticipate maintenance capital expenditures between $8.2 million and $10.2 million, and approved expenditures for expansion capital between $100.5 million and $110.5 million, for the year ending December 31, 2017. Forecasted growth capital expenditures include East Texas Processing consolidation, expansion of the Harvey terminal, continued build-out of the Bakken system, continued development of the Silver Dollar System and other organic growth projects.

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

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

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

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

Natural Gas Transportation Services and Offshore Pipelines and Services Segments. Profitability of our Natural Gas Transportation Services and Offshore Pipelines and Services segments are dependent upon the demand to transport natural gas pursuant under our firm and interruptible transportation contracts. Throughput volumes could decline should natural gas prices and drilling levels decline.

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

Average daily prices for NYMEX West Texas Intermediate crude oil ranged from a high of $54.45 per barrel to a low of $26.21 per barrel from January 1, 2016 through July 7, 2017. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.80 per MMBtu to a low of $1.49 per MMBtu from January 1, 2016 through July 7, 2017. We are unable to predict future potential movements in the market price for natural gas, crude oil and NGLs and thus, cannot predict the ultimate impact of prices on our operations. If commodity prices decline, this could lead to reduced profitability and may impact our liquidity, compliance with financial covenants in our revolving credit agreement, and our ability to maintain our current distribution levels. Our long-term view is that as economic conditions improve, commodity prices should reach levels that will support continued natural gas and crude oil production in the United States. Reduced profitability may result in future potential non-cash impairments of long-lived assets, goodwill, or intangible assets.

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

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

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

Results of Operations

Net loss attributable to the Partnership decreased by $148.5 million for the year ended December 31, 2016 as compared to 2015 primarily due to the loss on impairment of goodwill of $148.5 million recognized in 2015 and an increase in earnings from unconsolidated affiliates of $32.0 million from our investments in Delta House and the entities underlying the Emerald Transactions, offset by an increase in corporate expense of $21.6 million due to corporate relocation and JPE Merger expenses.

Total segment gross margin increased by $43.8 million, or 24.3%, for the year ended to December 31, 2016 to $223.6 million as compared to the same period in 2015 . The increase in total segment gross margin was primarily due to an increase in our Offshore Pipelines and Services segment gross margin of $48.7 million as a result of increased revenues received by the Partnership due to the Pascagoula plant shutdown. The Pascagoula plant is not controlled or owned by the Partnership, and the shutdown required volumes to be directed to our High Point system.

For the year ended December 31, 2016 , Adjusted EBITDA increased by $66.4 million, or 66.0% compared to 2015 . The increase is primarily related to higher distributions from our unconsolidated affiliates of $62.5 million largely due to our investments in Delta House and the entities underlying the Emerald Transactions.

We distributed $112.1 million and $100.4 million to holders of our common units during the year ended December 31, 2016 and 2015 , respectively.

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

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

	For the Years Ended December 31,		
	2016	2015	2014
Statements of Operations Data:			
Revenues:			
Commodity sales	$ 439,412	$ 613,241	$ 721,663
Services	151,231	135,718	116,195
Gains (losses) on commodity derivatives, net	(1,617)	1,345	1,091
Total revenue	589,026	750,304	838,949
Operating expenses:			
Cost of sales	393,351	567,682	672,948
Direct operating expenses	71,544	71,729	58,048
Corporate expenses	89,438	65,327	60,465
Depreciation, amortization and accretion	90,882	81,335	57,818
Loss on sale of assets, net	688	2,860	4,087
Loss on impairment of property, plant and equipment	697	—	21,344
Loss on impairment of goodwill	2,654	148,488	—
Total operating expenses	649,254	937,421	874,710
Operating loss	(60,228)	(187,117)	(35,761)
Other income (expenses):			
Interest expense	(21,433)	(20,077)	(16,497)
Loss on extinguishment of debt	—	—	(1,634)
Other expense	254	1,460	(1,096)
Earnings in unconsolidated affiliates	40,158	8,201	348
Income (loss) from continuing operations before income taxes	(41,249)	(197,533)	(54,640)
Income tax expense	(2,580)	(1,885)	(856)
Loss from continuing operations	(43,829)	(199,418)	(55,496)
Loss from discontinued operations	(4,715)	(423)	(24,071)
Net income (loss)	(48,544)	(199,841)	(79,567)
Net income (loss) attributable to noncontrolling interests	2,766	(13)	3,993
Net income (loss) attributable to the Partnership	$ (51,310)	$ (199,828)	$ (83,560)
Other Financial Data (1):			
Total segment gross margin	223,635	179,856	153,524
Adjusted EBITDA	$ 167,190	$ 100,721	$ 74,286

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

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

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

- a decrease in crude oil sales revenue of $152.9 million due to a decrease in sales volumes of 15,830 (bbls/day) from an overall reduction in our customer crude oil production volumes in our areas of operation;
- a decrease in natural gas revenue of $10.7 million primarily due to lower realized natural gas prices of $2.51 /Mcf, which is a decrease of $0.40 /Mcf or 13.7% period over period;
- a decrease in condensate revenues of $6.7 million due to lower realized condensate prices of $0.11 /gal or 11.3% period over period;
- a decrease in NGL revenues of $6.3 million due to lower gross NGL production volumes of 38.2 Mgal/d from our Gas Gathering and Processing Services segment and lower realized NGL prices of $0.57 /gal, which is a decrease of $0.01 /gal period over period; and
- these decreases were partially offset by an increase in crude oil gathering fee-based revenues of $4.7 million.

Service Revenue . Our service revenue for the year ended December 31, 2016 was $151.2 million compared to $135.7 million for the year ended December 31, 2015 . This increase of $15.5 million was primarily due to the following:

- an increase in firm and interruptible transportation of $8.5 million primarily as a result of the Pascagoula plant shutdown and additional revenue associated with our Gulf of Mexico Pipeline which we acquired in April 2016. The Pascagoula plant is not controlled or owned by the Partnership, and the shutdown required volumes to be redirected to our High Point system; and
- an increase in Terminalling Services segment revenue of $9.8 million as a result of incremental storage utilization and ancillary increases.

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

Total Segment Gross Margin . Total segment gross margin for the year ended December 31, 2016 , was $223.6 million compared to $179.9 million for the year ended December 31, 2015 . This increase of $43.7 million was primarily due to our increased Offshore Pipelines and Services segment gross margin of $8.5 million as a result of increased revenues received by the Partnership due to the Pascagoula plant shutdown. The Pascagoula plant is not controlled or owned by the Partnership, and the shutdown required volumes to be directed to our High Point system. Additionally, the incremental earnings from our equity method investees increased by $32.0 million, of which $29.9 million was attributable to our Offshore Pipelines and Services segment.

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

Corporate Expenses . Corporate expenses for the year ended December 31, 2016 , were $89.4 million compared to $65.3 million for the year ended December 31, 2015 . This increase of $24.1 million was primarily due to corporate relocation expenses of $9.1 million, JPE Merger expenses of $7.2 million, and increases in salaries, wages and benefits of $2.6 million due to increased employee expenses as we transitioned our corporate headquarters from Denver to Houston, information and technology maintenance costs of $1.1 million primarily related to systems and licenses that were implemented in the prior year, contract services of $1.0 million, and legal and regulatory compliance fees of $0.7 million in support of corporate activities.

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

Loss on Impairment of Goodwill. Goodwill impairment expense for the year ended December 31, 2015 was $148.5 million compared to $2.7 million for the year ended December 31, 2016. The 2015 impairment charges were comprised of $95.0 million and $23.6 million related to the Costar and Lavaca acquisitions, respectively, and $29.9 million in our Liquid Pipelines and Services reportable segment relating to our Crude Oil Supply and Logistics business. In 2016, we recognized goodwill impairment charges totaling $2.7 million related to our JP Liquids business. Given the market condition trend surrounding JP Liquids, we may recognize further impairments related to those assets in the future. Additionally, we recorded a goodwill impairment charge of $12.8 million during the year ended December 31, 2016 related to our Pinnacle Propane Express business which is classified in net loss from discontinued operations in the consolidated statement of operations.

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

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

Discontinued Operations. Loss from discontinued operations for the year ended December 31, 2016 was $4.7 million compared to $0.4 million for the year ended December 31, 2015. The increase in loss from discontinued operations of $4.3 million was primarily due to a decrease in gross margin of $1.9 million and $3.1 million associated with our Propane Business and Mid-Continent Business, respectively. The decrease in our Propane Business was primarily attributable to a reduction in NGL and refined product sales driven by a decline in volumes associated with oilfield services and overall warmer than normal temperatures sustained in the year ended December 31, 2016. The decrease in our Mid-Continent Business was primarily due to a decrease in crude oil sales volumes which was driven by a decline in oilfield services. Additionally, unrealized gains associated with the Propane commodity swaps decreased $10.7 million to $1.1 million as of December 31, 2016 from $11.8 million as of December 31, 2015, and loss on sale of assets related to the Propane Business increased $1.1 million for the year ended December 31, 2016. These increases in loss from discontinued operations are partially offset by a decrease of $12 million related to direct operating expenses, corporate expenses, and depreciation and amortization.

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

Commodity Sales . Commodity sales for the year ended December 31, 2015 was $613.2 million compared to $721.7 million for the year ended December 31, 2014 . This decrease of $108.5 million was primarily due to the following:

- a decrease of $47.0 million due to converting fixed-margin contracts in our Natural Gas Transportation Services segment to firm or interruptible transportation contracts;
- a decrease of $46.7 million due to the following:
  - lower realized natural gas prices of $2.91 /Mcf, which is a decrease of $2.01 /Mcf, or 40.9%, period over period,
  - lower realized NGL prices of $0.58 gal, which is a decrease of $0.33 /gal., or 36.3%, period over period, offset by higher gross NGL production volumes of 166.9 Mgal/d, or 260%, period over period, and
  - lower realized condensate prices of $0.97 /gal, which is a decrease of $0.65 /gal, or 40.1%, period over period, offset by higher gross condensate production volumes of 24.6 Mgal/d, or 32.7% , period over period; and
- a $12.9 million decrease due to a 48% reduction in crude prices from a 2014 WTI average of $93.26/bbl to a 2015 average of $0.46/gal.

***Services Revenue* .** Our service revenue for the year ended December 31, 2015 was $135.7 million compared to $116.2 million for the year ended December 31, 2014 . This increase of $19.5 million was primarily due an increase in the Terminalling Services segment revenue of $2.5 million as a result of increased storage utilization from acquiring new customers and contractual storage rate escalations.

Cost of Sales . Cost of sales for the year ended December 31, 2015 were $567.7 million compared to $672.9 million in the year ended December 31, 2014 . This decrease of $105.3 million was due to lower natural gas purchases of $94.3 million primarily as a result of lower natural gas prices and lower natural gas volumes related to our elective processing arrangements in our Gas Gathering and Processing segment, as well as the conversion of certain fixed-margin contracts to interruptible transportation contracts in our Natural Gas Transportation Services segment as mentioned above. Crude purchases decreased by $14.0 million due to a 48% reduction in crude prices from a 2014 WTI average of $93.26/bbl to a 2015 average of $0.46/gal. The price decline is slightly offset by increases in crude sales (24,643 bbls/day) and throughput volumes (7,378 bbls/day) due to expansions on our Silver Dollar Pipeline.

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

Total Segment Gross Margin . Total segment gross margin for the year ended December 31, 2015 was $179.9 million compared to $153.5 million for the year ended December 31, 2014. This increase of $26.4 million was primarily due to an increase in our Gas Gathering and Processing Services segment gross margin of $14.5 million as a result of higher NGL and condensate production of 166.9 Mgal/d and 24.6 Mgal/d, respectively, and higher throughput volumes of 63.4 MMcf/d.

Direct Operating Expenses . Direct operating expenses for the year ended December 31, 2015 were $71.7 million compared to $58.0 million in the year ended December 31, 2014 . This increase of $13.7 million was primarily due to $13.4 million of incremental operating costs, including costs related to direct labor and benefits, associated with the gathering and processing systems acquired from Costar in October 2014, and an increase of $2.1 million in operating costs associated with compression rentals used at our Lavaca System.

Corporate Expenses . Corporate expenses for the year ended December 31, 2015 were $65.3 million compared to $60.5 million for the year ended December 31, 2014 . This increase of $4.9 million was primarily due to personnel costs incurred to manage and integrate our recent acquisitions and support continuing growth.

Depreciation, Amortization and Accretion . Depreciation, amortization and accretion for the year ended December 31, 2015 was $81.3 million compared to $57.8 million for the year ended December 31, 2014 . This increase of $23.5 million was primarily due to incremental depreciation of fixed assets and amortization of certain intangible assets associated with the Costar Acquisition and the continuing capital expansion of the Lavaca System.

Loss on Impairment of Property, Plant and Equipment. During the fourth quarter of 2014, management noted the declining commodity markets and related impact on producers and shippers to whom we provide gathering and processing services. The decline in the market price of crude oil has led to a corresponding decrease in crude oil and natural gas production and is impacting the volume of natural and NGLs we gather and process on certain assets. As a result, asset impairment charges of $21.3 million related to certain gathering and processing assets were recorded during the fourth quarter of 2014.

Loss on Impairment of Goodwill. During the fourth quarter of 2015, management performed the Partnership's annual goodwill impairment test. As a result of the continuing decline in commodity prices, as well as the decline in the market price for the Partnership's common units during the fourth quarter, key assumptions relating to expected producer volumes and commodity prices used in management's impairment testing cash flow models were updated. The updated assumptions resulted in the estimated fair value of the Costar and Lavaca reporting units being less than their respective carrying values, indicating that the related goodwill was impaired. After completing an allocation of the estimated fair value of each reporting unit to the associated assets and liabilities, management determined that the goodwill of the Costar and Lavaca reporting units had a nominal fair value and that impairment charges of $118.6 million were required. We also recorded a goodwill impairment charge of $29.9 million during the year ended December 31, 2015 related to the JP Energy Crude Oil Supply and Logistics and JP Liquids reporting units.

Interest Expense . Interest expense for the year ended December 31, 2015 , was $20.1 million compared to $16.5 million for the year ended December 31, 2014 . This increase of $3.6 million was primarily due to higher outstanding borrowings under our revolving credit agreements primarily to fund our capital growth projects and the Costar acquisition and Delta House investment.

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

Discontinued Operations. Loss from discontinued operations for the year ended December 31, 2015 was $0.4 million compared to $24.1 million for the year ended December 31, 2015. The decrease in loss from discontinued operations of $23.6 million was primarily due to an increase in gross margin of $9.5 million associated with our Propane Business, primarily driven by more favorable propane hedge positions, offset by a decrease of $3.2 million in gross margin of the Mid-Continent Business which was driven by lower crude oil prices per barrel. Additionally, unrealized gains associated with our Propane commodity swaps increased $24.5 million to a $11.8 million unrealized gain as of December 31, 2015 from an unrealized loss position of $12.7 million as of December 31, 2014. We also had an incremental decrease of $9.6 million in loss from discontinued operations related to the sale of the Bakken Business in June 2014. These changes were partially offset by goodwill impairments of $12.9 million associated with our Mid-Continent Business for the year ended December 31, 2015, and an increase of $6.5 million related to direct operating expenses, corporate expenses, depreciation and amortization.

Results of Operations — Segment Results

Gas Gathering and Processing Services Segment

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

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Gas Gathering and Processing Services Segment			
Financial data:			
Commodity Sales	$ 91,444	$ 107,680	$ 148,198
Services	22,558	30,196	15,248
Revenue from operations	114,002	137,876	163,446
Gain (loss) on commodity derivatives, net	(833)	1,240	1,050
Segment revenue	$ 113,169	$ 139,116	$ 164,496
Cost of sales	63,832	72,960	112,719
Direct operating expenses	33,802	35,250	21,197
Other financial data:			
Segment gross margin	$ 48,245	$ 65,692	$ 51,213
Operating data:			
Average throughput (MMcf/d)	220.6	240.0	155.8
Average plant inlet volume (MMcf/d) (1)	102.1	120.9	89.1
Average gross NGL production (Mgal/d) (1)	192.9	231.1	64.2
Average gross condensate production (Mgal/d) (1)	82.9	97.1	70.8
Average realized prices:			
Natural gas ($/Mcf)	$ 2.06	$ 2.68	$ 4.57
NGLs ($/gal)	$ 0.57	$ 0.58	$ 0.91
Condensate ($/gal)	$ 0.87	$ 0.98	$ 1.60

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

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

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

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

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

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

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

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

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

Commodity Sales . Commodity sales for the year ended December 31, 2015 were $107.7 million compared to $148.2 million for the year ended December 31, 2014 . This decrease of $40.5 million was primarily due to the following:

- lower realized natural gas, NGL, and condensate prices of 41.4%, 36.6%, and 39%, respectively; and
- these decreases were partially offset by an increase in NGL and condensate production of 166.9 Mgal/d and 26.2 Mgal/d, respectively.

Services Revenue. *S* ervices revenue for the year ended December 31, 2015 were $30.2 million compared to $15.2 million for the year ended December 31, 2014 . This increase of $15.0 million was primarily due to higher throughput volumes of 84.2 MMcf/d related to the Costar and Lavaca acquisitions which occurred in 2014.

Cost of Sales . Cost of sales for the year ended December 31, 2015 were $73.0 million compared to $112.7 million for the year ended December 31, 2014 . This decrease of $39.7 million was primarily due to lower purchase costs associated with natural gas and NGLs due to lower realized natural gas and NGL prices and lower natural gas volumes associated with our elective processing arrangements. These decreases were partially offset by incremental purchases associated with off-spec NGL and condensate throughput volumes related to the Longview system.

Segment Gross Margin. Segment gross margin for the year ended December 31, 2015 was $65.7 million compared to $51.2 million for the year ended December 31, 2014 . This increase of $14.5 million was primarily due to incremental gross margin of $24.0 million on our Longview, Chapel Hill, Danville, and Yellow Rose systems and higher gross margin of $4.8 million at our Lavaca system. These increases were partially offset by lower NGL and condensate production associated with our elective processing arrangements.

Direct Operating Expenses . Direct operating expenses for the year ended December 31, 2015 were $35.3 million compared to $21.2 million for the year ended December 31, 2014 . This increase of $14.1 million was primarily due to incremental operating costs associated with the gathering and processing systems acquired in the Costar and Lavaca acquisitions, partially offset by the timing of activities related to our integrity management and plant repair and maintenance programs.

Liquid Pipelines and Services Segment

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

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Liquid Pipelines & Services			
Financial data:			
Commodity sales	$ 304,502	$ 457,448	$ 470,936
Services	19,063	23,008	22,239
Revenue from operations	323,565	480,456	493,175
Gains (losses) on commodity derivatives (net)	(341)	—	—
Earnings in unconsolidated affiliates	2,070	—	—
Segment revenue	$ 325,294	$ 480,456	$ 493,175
Cost of sales	293,618	454,057	468,137
Direct operating expense	10,091	9,912	7,209
Other financial data:			
Segment gross margin	$ 31,556	$ 26,399	$ 25,038
Operating data:			
Average throughput Pipeline (Bbls/d)	32,257	34,946	20,868
Average throughput Trucking (Bbls/d)	1,628	—	—

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

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

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

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

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

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

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

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

Commodity Sales . Commodity sales for the year ended December 31, 2015 were $457.4 million compared to $470.9 million for the year ended December 31, 2014. This decrease of $13.5 million was primarily due to the impact of the current lower priced crude oil market per barrel and the lack of any market dislocation opportunities for the year ended December 31, 2015. This decrease is partially offset by a $4.7 million increase in crude oil sales volumes, as sales volumes increased to 40,255 barrels per day for the year ended December 31, 2015 from 15,612 barrels per day for the year ended December 31, 2014 due to the expansions of the Silver Dollar Pipeline System in the third quarter of 2014 throughout 2015.

Services Revenue. Services revenue for the year ended December 31, 2015 were $23 million compared to $22.2 million for the year ended December 31, 2014. This increase of $0.7 million was primarily due to the incremental revenue from our Bakken system which commenced operations in 2015.

Cost of Sales . Cost of sales for the year ended December 31, 2015 were $454.1 million compared to $468.1 million for the year ended December 31, 2014. This decrease of $14.0 million was primarily due to the impact of the current lower priced crude oil market per barrel, as described above.

Segment Gross Margin . Segment gross margin for the year ended December 31, 2015 was $26.4 million compared to $25 million for the year ended December 31, 2014. This increase of $1.4 million was primarily due to an increase in production from the Bakken system which commenced operations in 2015.

Direct Operating Expenses . Direct operating expenses for the year ended December 31, 2015 were $9.9 million compared to $7.2 million for the year ended December 31, 2014. This increase of $2.7 million was primarily due to increases in insurance premiums of $0.8 million, property tax expenses of $0.2 million, and repairs and maintenance expenses of $0.2 million in 2015.

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).

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Natural Gas Transportation Services			
Financial data:			
Commodity Sales	$ 21,999	$ 23,972	$ 70,964
Services	18,109	16,035	12,925
Segment revenue	$ 40,108	$ 40,007	$ 83,889
Cost of sales	21,288	21,858	70,100
Direct operating expenses	5,923	6,728	6,975
Other financial data:			
Segment gross margin	$ 18,616	$ 18,073	$ 13,691
Operating data:			
Average throughput (MMcf/d)	389.9	364.1	373.3
Average firm transportation - capacity reservation (MMcf/d)	634.7	637.2	567.9
Average interruptible transportation - throughput (MMcf/d)	65.3	70.2	65.3
Average realized prices:			
Natural gas ($/Mcf)	$2.57	$2.86	$4.60

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

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

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

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

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

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

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

Commodity Sales . Commodity sales for the year ended December 31, 2015 were $24.0 million compared to $71.0 million for the year ended December 31, 2014. This decrease of $47.0 million was primarily due to converting certain fixed-margin arrangements to interruptible and firm transportation agreements during the first quarter of 2015, which substantially reduced the sales of natural gas throughput volumes and also the need for us to purchase such volumes.

Services Revenue. Services revenue for the year ended December 31, 2015 were $16.0 million compared to $12.9 million for the year ended December 31, 2014. This increase of $3.1 million was primarily due to an increase in firm transportation capacity commitments of 69 MMcf/d.

Cost of Sales . Cost of sales for the year ended December 31, 2015 were $21.9 million compared to $70.1 million for the year ended December 31, 2014. This decrease of $48.2 million was primarily due to converting certain fixed-margin arrangements to interruptible and firm transportation agreements during the first quarter of 2015, and therefore substantially reducing our need to purchase natural gas.

Segment Gross Margin . Segment gross margin for the year ended December 31, 2015 was $18.1 million compared to $13.7 million for the year ended December 31, 2014. This increase of $4.4 million was primarily due to an increase in firm transportation capacity and the incremental increase resulting from converting fixed-margin arrangements to interruptible and firm transportation agreements, as described above.

Direct Operating Expenses . Direct operating expenses for the year ended December 31, 2015 were $6.7 million compared to $7.0 million for the year ended December 31, 2014. This decrease of $0.3 million was primarily due to an ongoing cost cutting effort to reduce operating expenses.

Offshore Pipelines and Services Segment

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

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Offshore Pipelines & Services			
Financial data:			
Commodity sales	$ 6,812	$ 13,798	$ 20,044
Services	40,502	21,457	24,426
Revenue from operations	47,314	35,255	44,470
Gains (losses) on commodity derivatives, net	(7)	84	41
Earnings in unconsolidated affiliates	38,088	8,201	348
Segment revenue	$ 85,395	$ 43,540	$ 44,859
Cost of sales	3,049	9,914	15,133
Direct operating expense	10,945	9,425	11,142
Other financial data:			
Segment gross margin	$ 82,346	$ 33,613	$ 29,089
Operating data:			
Average throughput (MMcf/d)	466.4	442.8	524.6
Gross condensate production (Mgal/d)	3.6	2.7	4.4
Average firm transportation - capacity reservation (MMcf/d)	53.4	16.6	10.0
Average interruptible transportation - throughput (MMcf/d)	288.7	340.1	403.7
Average realized prices:			
Natural gas ($/Mcf)	$ 2.63	$ 2.97	$ 5.09
NGLs ($/gal)	$ —	$ 0.42	$ 0.88
Condensate ($/gal)	$ 0.72	$ 0.92	$ 1.89

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

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

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

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

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

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

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

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

Commodity Sales . Commodity sales for the year ended December 31, 2015 were $13.8 million compared to $20.0 million for the year ended December 31, 2014. This decrease of $6.2 million was primarily due to a reduction in the average realized prices for natural gas, NGLs, and condensate of 41.7%, 52.0%, and 51.3%, respectively.

Services Revenue. Service revenues for the year ended December 31, 2015 were $21.5 million compared to $24.4 million for the year ended December 31, 2014. This decrease of $2.9 million was primarily due to a decrease in average throughput and interruptible transportation throughput of 82 MMcf/d and 64 MMcf/d, respectively.

Cost of Sales . Cost of sales for the year ended December 31, 2015 were $9.9 million compared to $15.1 million for the year ended December 31, 2014. This decrease of $5.2 million was primarily due to lower realized commodity prices, as described above.

Earnings in Unconsolidated Affiliates. Earnings in unconsolidated affiliates for the year ended December 31, 2015 were $8.2 million compared to $0.3 million for the year ended December 31, 2014. This increase of $7.9 million was primarily due to the Delta House investment that occurred in September 2015.

Segment Gross Margin . Segment gross margin for the year ended December 31, 2015 was $33.6 million compared to $29.1 million for the year ended December 31, 2014. This increase of $4.5 million was primarily due to incremental earnings of $7.5 million associated with our investment in Delta House and higher earnings of $0.4 million from our investment in MPOG, partially offset by a decrease in average throughput volumes described above.

Direct Operating Expenses . Direct operating expenses for the year ended December 31, 2015 were $9.4 million compared to $11.1 million for the year ended December 31, 2014. This decrease of $1.7 million was primarily due to an ongoing effort to reduce operating expenses.

Terminalling Services Segment

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

	For the Years Ended December 31,		
	2016	2015	2014
Segment Financial and Operating Data:			
Terminalling Services			
Financial data:			
Commodity sales	$ 14,655	$ 10,343	$ 11,521
Services	50,999	45,022	41,357
Revenue from operations	65,654	55,365	52,878
Gains (losses) on commodity derivatives, net	(436)	21	—
Segment revenue	$ 65,218	$ 55,386	$ 52,878
Cost of sales	11,564	8,893	6,859
Direct operating expense	10,783	10,414	11,525
Other financial data:			
Segment gross margin	$ 42,872	$ 36,079	$ 34,493
Operating data:			
Contracted Capacity (Bbls)	5,011,133	4,487,542	4,247,058
Design Capacity (Bbls) (2)	5,173,717	4,688,950	4,363,817
Storage Utilization (1)	96.9%	95.7%	97.3%
Terminalling and storage throughput (Bbls/d)	56,741	62,075	63,859

(1) Excludes storage utilization associated with our discontinued operations.
(2) Excludes 1.2M Bbls at our North Little Rock and Caddo Mills locations.

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

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

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

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

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

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

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

Commodity Sales . Commodity sales for the year ended December 31, 2015 were $10.3 million compared to $11.5 million for the year ended December 31, 2014. The decrease of $1.2 million was attributable to a decrease in commodity prices of $4.1 million, partially offset by an increase in refined product sales volume of $3.0 million due to the addition of butane blending capabilities at our North Little Rock Terminal in the second quarter of 2015.

Services Revenue. Services revenue for the year ended December 31, 2015 were $45.0 million compared to $41.4 million for the year ended December 31, 2014 . The increase of $3.6 million was primarily attributable to increases in contracted storage capacity due to the expansion efforts at the Harvey terminal.

Cost of Sales. Cost of sales for the year ended December 31, 2015 were $8.9 million compared to $6.9 million for the year ended December 31, 2014. The increase of $2.0 million was primarily due to an increase in refined products sales volume.

Segment Gross Margin . Segment gross margin for the year ended December 31, 2015 was $36.1 million compared to $34.5 million for the year ended December 31, 2014 . The increase of $1.6 million was primarily attributable to an increase in storage revenue while managing direct labor costs associated with providing ancillary services.

Direct Operating Expenses . Direct operating expenses for the year ended December 31, 2015 were $10.4 million compared to $11.5 million for the year ended December 31, 2014 . The decrease of $1.1 million is primarily attributable to managing direct labor associated with providing ancillary services.

Liquidity and Capital Resources

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

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

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

- The issuance in April 2016 of 8,571,429 Series C Units along with warrants to purchase up to 800,000 common units at an exercise price of $7.25 per common unit with a combined issuance date fair value of approximately $120.0 million , proceeds of which were used to partially fund the purchase our membership interests in the entities underlying the Emerald Transactions.

- The issuance in October of 2,333,333 Series D Units with a value of $34.5 million , the proceeds of which were used to partially fund the purchase of additional Delta House Class A Units. We also agreed to grant the Series D unitholders a warrant to purchase up to 700,000 common units at an exercise price of $22.00 per common unit if the Series D Units are still outstanding at June 30, 2017.

- Revolving credit agreements borrowings of $425.1 million and repayments of $224.0 million .

- Issuance of the 3.77% Senior Notes resulting in net proceeds of approximately $57.7 million .

- Issuance of 8.50% Senior Notes resulting in net proceeds of approximately $291.3 million .

Changes in natural gas, crude oil, NGL and condensate prices and the terms of our customer contracts have a direct impact on our generation and use of cash from operations due to their impact on net income (loss), along with the resulting changes in working capital. During 2016, we mitigated a portion of our anticipated commodity price risk associated with the volumes from our gathering and processing activities with fixed price commodity swaps. For additional information regarding our derivative activities, please read Item 7A, "Quantitative and Qualitative Disclosures about Market Risk" included in the 2016 Form 10-K.

The counterparties to 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 respective assessments of creditworthiness. The assessment of our position with respect to the collateral thresholds is determined on a counterparty by counterparty basis, and is impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative natural gas and crude oil forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. As of December 31, 2016 , we are not required to post collateral with our counterparties.

At-The-Market ("ATM") Offering

On October 18, 2015, we filed a prospectus supplement related to the offer and sale from time to time of up to $100.0 million of our common units through an at-the-market offering program. For the year ended December 31, 2016 , we sold 248,561 common units resulting in net proceeds of $2.9 million, after deducting offering costs of $0.3 million . The net proceeds were used to repay amounts outstanding under the Partnership Credit Agreement. As of December 31, 2016 , approximately $96.8 million remained available for sale under the program.

AMID Credit Agreement

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

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

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

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

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

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

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

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

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

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

JPE Credit Agreement

On February 12, 2014, JPE entered into the JPE Credit Agreement with Bank of America, N.A, which was available for refinancing and repayment of certain existing indebtedness, working capital, capital expenditures, permitted acquisitions and other general partnership purposes. The JPE Credit Agreement consisted of a $275.0 million revolving loan, which included a sub-limit of up to $100.0 million for letters of credit. The JPE Credit Agreement was scheduled to mature on February 12, 2019, but was paid off and terminated on March 8, 2017 in connection with the Partnership's acquisition of JPE.

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

8.50% Senior Notes

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

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

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

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

- at least 65% of the aggregate principal amount of the 8.50% Senior Notes remains outstanding immediately after such redemption (excluding 8.50% Senior Notes held by the Partnership and its subsidiaries); and
- the redemption occurs within 180 days of the closing of each such equity offering.

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

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

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

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

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

3.77% Senior Notes

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

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

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

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

Working Capital

Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received from our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors. Our working capital deficit was $16.4 million at December 31, 2016 compared to a surplus of $6.6 million at December 31, 2015 with the $23.0 million increase in the deficit due primarily to capital expenditures in connection with the Midla-Natchez Line and convertible preferred unit distributions which were included in *Accrued expenses and other current liabilities* at December 31, 2016. The Partnership plans to utilize the increase in the Second Amended and Restated Credit Agreement of $150.0 million to cover any working capital requirements.

Cash Flows

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

	For the Years Ended December 31,		
	2016	**2015**	**2014**
Net cash provided by (used in):			
Operating activities	$ 90,639	$ 86,978	$ 51,635
Investing activities	(564,504)	(250,769)	(518,023)
Financing activities	477,544	161,954	466,577

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

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

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

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

Financing Activities . Net cash provided by financing activities was $477.5 million for the year ended December 31, 2016 , compared to net cash provided by financing activities of $162.0 million for the year ended December 31, 2015 . Cash provided by financing activities for the year ended December 31, 2016 increased by $315.5 million period over period primarily due proceeds from the 8.50% Senior Notes of $294.0 million , proceeds from the 3.77% Senior Notes of $60.0 million , partially offset by lower borrowings primarily on our revolving credit agreements of $46.2 million.

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

Operating Activities . Net cash provided by operating activities was $87.0 million for the year ended December 31, 2015 , compared to $51.6 million for the year ended December 31, 2014 . Net cash provided by operating activities for the year ended December 31, 2015 , increased by $35.3 million period over period mainly driven by a decrease in net loss of $28.2 million, excluding the $148.5 million goodwill impairment charge recorded in 2015.

Investing Activities . Net cash used in investing activities was $250.8 million for the year ended December 31, 2015 , compared to $518.0 million for the year ended December 31, 2014 . Cash used in investing activities for the year ended December 31, 2015 decreased by $267.2 million period over period primarily due to a decrease in cost of acquisitions of $357.1 million, return of restricted cash of $16.2 million , and higher cash disbursements received from unconsolidated affiliates in excess of cumulative earnings of $10.7 million . These increases were offset by higher capital expenditures of $54.2 million primarily related to the Lavaca and Bakken Systems, and higher acquisitions of unconsolidated affiliates of $53.7 million related to equity method investments primarily related to the Delta House Investment.

Financing Activities . Net cash provided by financing activities was $162.0 million for the year ended December 31, 2015 , compared to $ 466.6 million for the year ended December 31, 2014. Cash provided by financing activities for the year ended December 31, 2014 decreased by $304.6 million primarily due to lower proceeds from the issuance of common units to the public of $384.4 million , offset by higher net borrowings on debt of $83.5 million .

Off-Balance Sheet Arrangements

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

Capital Requirements

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

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

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

Historically, our maintenance capital expenditures have not included all capital expenditures required to maintain volumes on our systems. It is customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future. For the year ended December 31, 2016 , capital expenditures totaled $147.8 million including expansion capital expenditures of $137.3 million, maintenance capital expenditures of $6.8 million and reimbursable project expenditures (capital expenditures for which we expect to be reimbursed for all or part of the expenditures by a third party) of $3.7 million . Although we classified our capital expenditures as expansion and maintenance, we believe those classifications approximate, but do not necessarily correspond to, the definitions of estimated maintenance capital expenditures and expansion capital expenditures under our Partnership Agreement. We anticipate maintenance capital expenditures related to the Partnership between $8.2 million and $10.2 million and expansion capital expenditures between $100.5 million and $110.5 million for the year ending December 31, 2017 . Forecasted growth capital expenditures include East Texas Processing consolidation, expansion of the Harvey terminal, continued build-out of the Bakken system, continued development of the Silver Dollar System, and other organic growth projects.

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

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

Integrity Management

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

Distributions

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

On January 26, 2017, we announced that the Board of Directors of our General Partner declared a quarterly cash a distribution of $0.4125 per American Midstream common unit for the fourth quarter ended December 31, 2016, or $1.65 per common unit on an annualized basis. The cash distribution was paid on February 13, 2017, to unitholders of record as of the close of business on February, 6 2017. A distribution of $0.3250 per JPE common unit and subordinated unit for the three months ended December 31, 2016 was declared on January 24, 2017 and paid on February 14, 2017 to unitholders of record as of February 7, 2017.

Contractual Obligations

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

	Total	Revolving Credit Agreements	3.77% Senior Notes	8.50% Senior Notes	Asset Retirement Obligation (1)	Other
Less Than 1 Year	$ 15,604	$ —	$ 1,677	$ —	$ 6,499	$ 7,428
1 - 3 Years	900,185	888,250	3,039	—	—	8,896
3 - 5 Years	311,643	—	6,729	300,000	—	4,914
More Than 5 Years	110,909	—	48,555	—	44,363	17,991
Total	$ 1,338,341	$ 888,250	$ 60,000	$ 300,000	$ 50,862	$ 39,229

(1) In some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's experience, or the asset's estimated economic life.

Impact of Seasonality

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

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

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Critical Accounting Policies and Estimates

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

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

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

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

Impairment of Long-Lived Assets . We evaluate the recoverability of our property, plant and equipment and intangible assets with definite lives when events or circumstances indicate we may not recover the carrying amount of the assets. We continually monitor our operations, the market, and business environment to identify indicators that could suggest an asset or asset group may not be recoverable. We evaluate the asset or asset group for recoverability by estimating the undiscounted future cash flows expected to be derived from their use and disposition. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. An asset or asset group is considered impaired when the estimated undiscounted cash flows are less than the carrying amount. In that event, an impairment loss is recognized to the extent that the carrying amount of the asset or asset group exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of fair values using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations.

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

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

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

Asset Retirement Obligations. Asset retirement obligations ("ARO") are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and operation. An ARO is initially measured at its estimated fair value. Upon initial recognition, we also record an increase to the carrying amount of the related long-lived asset. We depreciate the asset using the straight-line method over the period during which it is expected to provide benefits. After initial recognition, we revise the ARO to reflect the passage of time and for changes in the estimated amount or timing of cash flows.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for certain of our offshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's experience, or the asset's estimated economic life. The useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

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

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

We used mark-to-market accounting for our commodity hedges and interest rate swaps. We record monthly realized gains and losses on hedge instruments based upon cash settlements information. The settlement amounts vary due to the volatility in the commodity market prices throughout each month. We also record unrealized gains and losses for the net change in the mark-to-market valuation of the hedges.

Recent Accounting Pronouncements.

For information regarding new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements, please refer to Note 1 "Organization, Basis of Presentation and Summary of Significant Accounting Policies" in our Recast Form 8-K filed on December 7, 2016 and dated December 6, 2017, which is incorporated herein by reference.