Sanchez Midstream Partners LP
Form 10-Q
August 14, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2017

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to .

Commission File Number 001-33147

Sanchez Midstream Partners LP

(Exact name of registrant as specified in its charter)

Delaware	11-3742489
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1000 Main Street, Suite 3000	
Houston, Texas	77002
(Address of Principal Executive Offices)	(Zip Code)

(713) 783-8000

(Registrant's Telephone Number, Including Area Code)

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial standards provided pursuant to Section 13(a) of the Exchange Act.

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

Common units outstanding as of August 10, 2017: Approximately 14,602,148 units.

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Cautionary Note Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q contains “forward-looking statements” as defined by the Securities and Exchange Commission that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include discussions about our business strategy; acquisition strategy; financing strategy; ability to make, maintain and grow distributions; the ability of our customers to meet their drilling and development plans on a timely basis or at all and perform under gathering and processing agreements; future operating results; future capital expenditures; and plans, objectives, expectations, forecasts, outlook and intentions. All of these types of statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Part I, Item 2. and other items within this Quarterly Report on Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “t negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by the management of our general partner. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate.

Important factors that could cause our actual results to differ materially from the expectations reflected in the forward looking statements include, among others:

- our ability to successfully execute our business, acquisition and financing strategies;
- our ability to utilize the services, personnel and other assets of the sole member of our general partner, SP Holdings, LLC (“Manager”), pursuant to existing services agreements;
- our ability to make, maintain and grow distributions;
- the timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids (“NGLs”), natural gas and related commodities;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise;
- the ability of our customers to meet their drilling and development plans on a timely basis or at all and perform under gathering and processing agreements which may affect our throughput rates;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
- the credit worthiness and performance of our counterparties, including financial institutions, operating partners and other parties;
- competition in the oil and natural gas industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- our ability to compete with other companies in the oil and natural gas industry;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
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the extent to which our crude oil and natural gas properties operated by others are operated successfully and economically;

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- the use of competing energy sources and the development of alternative energy sources;
- unexpected results of litigation filed against us;
- the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage; and
- the other factors described under “Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Part II, Item 1A. Risk Factors” and elsewhere in this Quarterly Report on Form 10 Q and in our other public filings with the Securities and Exchange Commission.

Management cautions all readers that the forward-looking statements contained in this Quarterly Report on Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Operations

(In thousands, except unit data)

(Unaudited)

	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Revenues				
Natural gas sales	$ 2,252	$ 600	$ 5,031	$ 4,275
Oil sales	8,109	(2,756)	19,459	2,587
Natural gas liquids sales	492	244	959	520
Gathering and transportation sales	14,176	14,258	25,387	28,133
Total revenues	25,029	12,346	50,836	35,515
Expenses:				
Operating expenses:				
Lease operating expenses	3,881	4,178	8,864	9,151
Transportation operating expenses	3,032	3,014	6,328	6,068
Cost of sales	40	63	77	193
Production taxes	353	326	826	547
General and administrative	6,353	4,978	11,962	10,697
Unit-based compensation expense	780	1,091	1,320	1,529
Depreciation, depletion and amortization	8,937	6,129	21,118	13,317
Asset impairments	—	—	4,688	1,309
Accretion expense	240	315	498	630
Total operating expenses	23,616	20,094	55,681	43,441
Other (income) expense				
Interest expense, net	1,896	1,103	3,779	2,002
Gain on embedded derivatives	—	(6,898)	—	(13,192)
Earnings from equity investments	(1,042)	—	(1,524)	(12)
Other income	—	(1)	—	(49)
Total other (income) expenses	854	(5,796)	2,255	(11,251)
Total expenses	24,470	14,298	57,936	32,190
Income (loss) before income taxes	559	(1,952)	(7,100)	3,325
Income tax expense	—	—	—	—
Net income (loss)	559	(1,952)	(7,100)	3,325
Less:				
Preferred unit distributions paid in common units	—	—	(2,625)	—
Preferred unit distributions	(8,750)	(8,750)	(15,750)	(17,500)
Preferred unit amortization	(433)	(6,505)	(837)	(13,772)

Net loss attributable to common unitholders	$ (8,624)	$ (17,207)	$ (26,312)	$ (27,947)
Net loss per unit				
Net loss per unit				
Common units - Basic and Diluted	$ (0.62)	$ (4.37)	$ (1.92)	$ (8.38)
Weighted Average Units Outstanding				
Common units - Basic and Diluted	13,939,993	3,935,297	13,671,557	3,333,482

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Balance Sheets

(In thousands, except unit data)

ASSETS	June 30, 2017 (Unaudited)	December 31, 2016
Current assets		
Cash and cash equivalents	$ 2,031	$ 957
Restricted cash	250	—
Accounts receivable	1,581	1,212
Accounts receivable - related entities	4,812	5,987
Prepaid expenses	2,608	2,041
Fair value of derivative instruments	5,993	4,568
Total current assets	17,275	14,765
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	757,705	758,913
Gathering and transportation assets	176,195	152,209
Material and supplies	1,056	1,056
Less: accumulated depreciation, depletion, amortization and impairment	(708,315)	(689,358)
Oil and natural gas properties and equipment, net	226,641	222,820
Other assets		
Intangible assets, net	178,942	185,766
Fair value of derivative instruments	6,291	3,964
Equity investments	117,519	111,614
Other non-current assets	647	776
Total assets	$ 547,315	$ 539,705
LIABILITIES AND PARTNERS' CAPITAL		
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 1,244	$ 951
Accounts payable and accrued liabilities - related entities	14,822	7,046
Royalties payable	535	706
Fair value of derivative instruments	21	740
Total current liabilities	16,622	9,443
Other liabilities		
Asset retirement obligation	14,227	13,579
Long-term debt, net of debt issuance costs	176,554	151,322
Fair value of derivative instruments	—	1,356
Other liabilities	4,049	4,270
Total other liabilities	194,830	170,527
Total liabilities	211,452	179,970
Commitments and contingencies (See Note 11)		
Mezzanine equity		

Class B preferred units, 31,000,887 and 29,296,441 units issued and outstanding as of June 30, 2017 and December 31, 2016, respectively	342,953	342,991
Partners' capital (deficit)		
Common units, 14,606,028 and 13,447,749 units issued and outstanding as of June 30, 2017 and December 31, 2016, respectively	(7,090)	16,744
Total partners' capital (deficit)	(7,090)	16,744
Total liabilities and partners' capital	$ 547,315	$ 539,705

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(In thousands)

(unaudited)

	Six Months Ended June 30, 2017	2016
Cash flows from operating activities:		
Net income (loss)	$ (7,100)	$ 3,325
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	14,294	7,262
Amortization of debt issuance costs	259	246
Revisions to asset retirement obligation included in DD&A	—	(862)
Asset impairments	4,688	1,309
Accretion expense	498	630
Distributions from equity investments	3,684	—
Equity earnings in affiliate	(1,524)	(12)
Bad debt expense	—	35
Gain from disposition of property and equipment	—	(9)
Total mark-to-market on commodity derivative contracts	(9,268)	3,736
Cash settlements on commodity derivative contracts	3,378	13,028
Unit-based compensation expense	2,019	1,952
Gain on embedded derivative	—	(13,192)
Amortization of intangible assets	6,824	6,917
Costs for plug and abandon activities	(45)	(86)
Changes in Operating Assets and Liabilities:		
Accounts receivable	(369)	313
Accounts receivable - related entities	(125)	(5,836)
Prepaid expenses	(567)	(1,414)
Other assets	(146)	659
Accounts payable and accrued liabilities	7,309	(3,128)
Accounts payable and accrued liabilities - related entities	(222)	2,634
Royalties payable	(171)	(190)
Net cash provided by operating activities	23,416	17,317
Cash flows from investing activities:		
Development of oil and natural gas properties	(210)	(2,269)
Proceeds from sale of oil and natural gas properties	—	16
Final settlement of oil and natural gas properties acquisition	1,468	—
Development of gathering and transportation assets	(15,240)	—
Purchases of equity investments	(8,286)	—
Net cash used in investing activities	(22,268)	(2,253)
Cash flows from financing activities:		
Payments for offering costs	(293)	(87)
Proceeds from issuance of debt	25,000	2,000

Repurchase of common units under repurchase program	—	(2,948)
Units tendered by employees for tax withholdings	—	(140)
Distributions to common unitholders	(12,044)	(3,025)
Proceeds from issuance of common units	1,290	—
Class B preferred unit cash distributions	(14,000)	(16,168)
Debt issuance costs	(27)	(64)
Net cash used in financing activities	(74)	(20,432)
Net increase (decrease) in cash and cash equivalents	1,074	(5,368)
Cash and cash equivalents, beginning of period	957	6,571
Cash and cash equivalents, end of period	$ 2,031	$ 1,203
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 8,601	$ 1,609
Change in asset retirement obligations	$ 195	$ —
Cash paid during the period for interest	$ 3,458	$ 1,732
Earnout liability	$ 221	$ —

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP and SUBSIDIARIES

Condensed Consolidated Statements of Changes in Partners' Capital for the Six Months Ended June 30, 2017

(In thousands, except unit data)

(Unaudited)

	Class A Preferred Units		Common Units		Total
	Units	Amount	Units	Amount	Capital
Partners' Capital (Deficit), December 31, 2015	11,694,364	$ 17,112	3,240,813	$ (45,285)	$ (28,173)
Units tendered by employees for tax withholding	—	—	(12,227)	(140)	(140)
Units forfeited by employees	—	—	(2,000)	—	—
Unit-based compensation programs	—	—	67,627	2,044	2,044
Issuance of common units, net of offering costs of $5.3 million	—	—	9,226,595	96,278	96,278
Class A Preferred Units converted to common units	(11,694,364)	(17,112)	1,169,441	17,112	—
Common units retired via unit repurchase program	—	—	(242,500)	(2,948)	(2,948)
Cash distributions to common unit holders	—	—	—	(6,696)	(6,696)
Distributions - Class B preferred units	—	—	—	(62,852)	(62,852)
Net income	—	—	—	19,231	19,231
Partners' Capital, December 31, 2016	—	—	13,447,749	16,744	16,744
Unit-based compensation programs	—	—	215,814	2,019	2,019
Issuance of common units, net of offering costs of $0.3 million	—	—	549,174	7,253	7,253
Cash distributions to common unit holders	—	—	—	(12,044)	(12,044)
Common units issued as Class B Preferred distributions	—	—	393,291	5,250	5,250
Distributions - Class B preferred units	—	—	—	(19,212)	(19,212)
Net loss	—	—	—	(7,100)	(7,100)
Partners' Capital (Deficit), June 30, 2017	—	$ —	14,606,028	$ (7,090)	$ (7,090)

See accompanying notes to condensed consolidated financial statements.

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SANCHEZ MIDSTREAM PARTNERS LP AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. ORGANIZATION AND BUSINESS

Organization

Sanchez Midstream Partners LP, a Delaware limited partnership ("SNMP," "we," "us," "our" or the "Partnership") (formerly Sanchez Production Partners LP), is a growth oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and production assets in North America. SNMP completed its initial public offering on November 20, 2006, as Constellation Energy Partners LLC ("CEP" or the "Company"). We have entered into a shared services agreement (the "Services Agreement") with SP Holdings, LLC (the "Manager"), the sole member of our general partner, pursuant to which the Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services. On March 6, 2015, the Company's unitholders approved the conversion of Sanchez Production Partners LLC to a Delaware limited partnership and the name was changed to Sanchez Production Partners LP. On June 2, 2017, Sanchez Production Partners LP changed its name to Sanchez Midstream Partners LP. Manager owns the general partner of SNMP and all of SNMP's incentive distribution rights. Our common units are currently listed on the NYSE American under the symbol "SNMP," and were traded under the symbol "SPP" prior to our recent name change.

Historically, our operations have consisted of the production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("Sanchez Energy") and entered into a 15-year gathering and processing agreement with Sanchez Energy. We also commenced a process to sell our oil and natural gas properties in the Mid-Continent region. In July 2016, we sold a portion of our production assets in the Mid-Continent region and acquired a 50% equity interest in Carnero Gathering, LLC ("Carnero Gathering"). In November 2016, we completed a public offering of approximately 6,745,107 common units (which includes exercise of the underwriters' option to purchase 194,305 common units) for net proceeds of approximately $69.7 million, after deducting customary offering expenses. Concurrent with the public offering, we completed a private placement of 2,272,727 common units representing limited partner interests for net proceeds of approximately $25.0 million. The combined proceeds were used to close the acquisition of a 50% equity interest in Carnero Processing, LLC ("Carnero Processing") and the acquisition of working interests in 23 producing Eagle Ford Shale wellbores located in Dimmit and Zavala counties in South Texas and escalating working interests in an additional 11 producing wellbores in the Palmetto Field in Gonzales, Texas. In July 2017, we sold our equity interests in the entities that owned our remaining operated Oklahoma production assets for cash consideration of $5.5 million, subject to customary post-closing adjustments, and assumption by the buyer of certain plugging and abandonment costs. On June 30, 2017, we signed a purchase and sale agreement to sell certain oil and natural gas properties in Texas.

2. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These unaudited condensed consolidated financial statements include the accounts of SNMP and our wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation. We conduct our business activities as two operating segments: the production of oil and natural gas and the midstream business, which includes Western Catarina Midstream (defined below). Our management evaluates performance based on these two business segments.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules of the Securities and Exchange Commission ("SEC"). Certain information and footnote disclosures, normally included in annual financial statements prepared in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"), have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information presented not misleading. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, necessary to fairly state the financial position, results of operations and cash flows with respect to the interim condensed consolidated financial statements have been included. The results of operations for the interim periods are not necessarily indicative of the results for the entire year.

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These unaudited condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto of SNMP and its subsidiaries included in our Annual Report on Form 10-K for the year ended December 31, 2016, which was filed with the SEC on March 28, 2017.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("FASB"), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our condensed consolidated financial statements upon adoption.

In January 2017, the FASB issued Accounting Standards Update ("ASU") 2017-01 "Business Combinations (Topic 805): Clarifying the Definition of a Business," which provides a new framework for determining whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, and the Partnership is currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In December 2016, the FASB issued ASU 2016-19 "Technical Corrections and Improvements," which amends a number of Topics in the FASB ASC. The ASU is part of an ongoing FASB project to facilitate codification updates for non-substantive technical corrections, clarifications, and improvements that are not expected to have a significant effect on accounting practice or create a significant administrative cost to most entities. The ASU will apply to all reporting entities within the scope of the affected accounting guidance. Most amendments are effective upon issuance (December 2016).

In November 2016, the FASB issued ASU 2016-18 "Statement of Cash Flows (Topic 230): Restricted Cash," which requires companies to include cash and cash equivalents that have restrictions on withdrawal or use in total cash and cash equivalents on the statement of cash flows. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, and the Partnership is currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In October 2016, the FASB issued ASU 2016-16 "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory," which eliminates a current exception in U.S. GAAP to the recognition of the income tax effects of temporary differences that result from intra-entity transfers of non-inventory assets. The intra-entity exception is being eliminated under the ASU. The standard is required to be applied on a modified retrospective basis and will be effective beginning with the first quarter 2018. Early adoption is permitted, and the Partnership is currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016-15, "Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments" effective for annual and interim periods beginning after December 15, 2017. This ASU is intended to clarify the presentation of cash receipts and payments in specific situations. Early adoption is permitted including adoption in an interim period. We chose to adopt ASU 2016-15 for the year ended December 31, 2016 on a retrospective basis.

In March 2016, the FASB issued ASU No. 2016-09 "Improvements to Employee Share-Based Payment Accounting," effective for annual and interim periods for public companies beginning after December 15, 2016, with a cumulative-effect and prospective approach to be used for implementation. ASU 2016-09 changes several aspects of the accounting for share-based payment award transactions including accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, minimum statutory tax withholding requirements and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. The adoption of this guidance did not have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02 “Leases (Topic 842),” effective for annual and interim periods for public companies beginning after December 15, 2018, with a modified retrospective approach to be used for implementation. ASU 2016-02 updates the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee’s classification of a finance lease. The Partnership will not early adopt this standard, and will apply the revised lease rules for our interim and annual reporting periods starting January 1, 2019. The Partnership is currently evaluating the impact of these rules on its consolidated financial statements and has started the assessment process by evaluating the population of leases under the revised definition. The adoption of this standard will result in an increase in the assets and liabilities on the Partnership’s consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

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In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." In March, April, and May of 2016, the FASB issued rules clarifying several aspects of the new revenue recognition standard. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new standard also requires more detailed disclosures related to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The Partnership will not early adopt the standard although early adoption is permitted. The Partnership's expectation is to apply the modified retrospective approach. As part of the assessment, the Partnership has formed an implementation work team, completed trainings on the new revenue recognition model and gathered a representative sample of material revenue contracts covering current revenue streams for which we are currently evaluating the impact under the new standard. The Company is currently collecting all remaining contracts and evaluating the impacts to its consolidated financial statements under the revised standards.

Use of Estimates

The condensed consolidated financial statements are prepared in conformity with U.S. GAAP, which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

3. ACQUISITIONS AND DIVESTITURES

Our acquisitions are accounted for under the acquisition method of accounting in accordance with Accounting Standards Codification ("ASC") Topic 805, "Business Combinations." A business combination may result in the recognition of a gain or goodwill based on the measurement of the fair value of the assets acquired at the acquisition date as compared to the fair value of consideration transferred, adjusted for purchase price adjustments. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates. The results of operations of the properties obtained through our acquisitions have been included in the condensed consolidated financial statements since the closing dates of the acquisitions.

Non-Operated Production Divestiture

On July 14, 2017, we entered into an agreement to assign certain non-operated production assets located in Oklahoma, as well as our equity interests in the entities that owned the assets, in exchange for agreeing upon the apportionment of certain shared litigation costs (the "Non-Operated Production Divestiture"). The assignment was effective as of July 14, 2017, and we anticipate recording a gain on the sale during the third quarter 2017.

Texas Production Divestiture

On June 30, 2017, we entered into a purchase and sale agreement to sell certain non-operated production assets located in Texas for cash consideration of approximately $6.3 million, subject to adjustment for title and environmental defects (the “Texas Production Divestiture”), and assumption by the buyer of all obligations relating to the assets, including all plugging and abandonment costs relating to the assets. The transaction is expected to close in the third quarter 2017, and we anticipate recording a gain on the sale at such time.

Oklahoma Production Divestiture

On May 10, 2017, we entered into a purchase and sale agreement to sell all of the Partnership’s equity interests in the entities that owned our remaining Oklahoma production assets for cash consideration of $5.5 million, subject to adjustment for title and environmental defects (the “Oklahoma Production Divestiture”), and assumption by the buyer of all obligations relating to the assets arising after the closing date and all plugging and abandonment costs relating to the assets arising prior to the closing date. The transaction closed July 17, 2017, and we anticipate recording a gain on the sale during the third quarter 2017.

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Carnero Processing Acquisition

On November 22, 2016, we completed the acquisition of 50% of the outstanding membership interests in Carnero Processing from SN Midstream, LLC, a wholly-owned subsidiary of Sanchez Energy (“SN Midstream”), for cash consideration of approximately $55.5 million and the assumption of approximately $24.5 million of remaining capital commitments to Carnero Processing (the “Carnero Processing Transaction”). The remaining 50% membership interests in Carnero Processing are owned by TPL SouthTex Processing Company LP, an affiliate of Targa Resources Group (“Targa”). Carnero Processing owns a cryogenic gas processing facility located in La Salle County, Texas that is operated by Targa (the “Raptor Gas Processing Facility”). See Note 10. “Investments” for additional information relating to the Carnero Processing Transaction.

The Partnership made capital contributions to Carnero Processing totaling $14.1 million between November 22, 2016 and June 30, 2017.

Production Acquisition

On November 22, 2016, we completed the acquisition from SN Cotulla Assets, LLC and SN Palmetto, LLC, each a wholly-owned subsidiary of Sanchez Energy, of working interests in 23 producing Eagle Ford Shale wellbores located in Dimmit and Zavala counties in South Texas together with escalating working interests in an additional 11 producing wellbores located in the Palmetto Field in Gonzales County, Texas for aggregate cash consideration of approximately $24.2 million after approximately $2.8 million in normal and customary closing adjustments (the “Production Acquisition”). The effective date of the transaction was July 1, 2016. The Production Acquisition included initial conveyed working interests and net revenue interests which, for certain properties, escalated on January 1, 2017 and will escalate again on January 1, 2018, at which point, SNMP’s interests in the Production Acquisition properties will stay constant for the remainder of the respective lives of the assets.

The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved developed reserves	$ 25,016
Fair value of assets acquired	25,016
Asset retirement obligations	(832)
Fair value of net assets acquired	$ 24,184

Carnero Gathering Transaction

On July 5, 2016, we completed the acquisition of 50% of the outstanding membership interests in Carnero Gathering from SN Midstream for cash consideration of approximately $37.0 million, and the assumption of approximately $7.4 million of remaining capital commitments to Carnero Gathering (the “Carnero Gathering Transaction”). In addition, the Partnership is required to pay SN Midstream a monthly earnout based on gas received from SN Catarina, LLC, a wholly-owned subsidiary of Sanchez Energy (“SN Catarina”), at Carnero Gathering’s receipt points, as well as gas delivered and processed at the Raptor Gas Processing Facility for other producers. The remaining 50% membership interests in Carnero Gathering are owned by Targa. Carnero Gathering owns a gas gathering pipeline in the Western Eagle Ford in South Texas that is operated by Targa and interconnects with the Raptor Gas Processing Facility. See Note 10. “Investments” for additional information relating to the Carnero Gathering Transaction.

The Partnership made capital contributions to Carnero Gathering totaling $8.1 million between July 5, 2016 and June 30, 2017.

Mid-Continent Divestiture

On June 15, 2016, certain wholly-owned subsidiaries of the Partnership entered into an agreement with Gateway Resources U.S.A., Inc. (“Gateway”) to sell substantially all of the Partnership’s operated production assets in Oklahoma and Kansas (other than those arising under or related to a concession agreement with the Osage Nation) (the “Mid-Continent Divestiture”) for cash consideration of $7,120, subject to adjustment for title and environmental defects, effective as of August 1, 2016. In addition, Gateway agreed to assume all obligations relating to the assets arising after the effective date and all plugging and abandonment costs relating to the assets arising prior to the effective date. The Partnership closed the sale of this transaction on July 15, 2016. The Partnership recorded a $0.2 million loss related to an intangible asset balance comprised of marketing contracts from the 2007 Newfield acquisition which were included in the Mid-Continent Divestiture.

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4. FAIR VALUE MEASUREMENTS

Measurements of fair value of derivative instruments are classified according to the fair value hierarchy, which prioritizes the inputs to the valuation techniques used to measure fair value. Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that can be valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2017 (in thousands):

	Fair Value Measurements at June 30, 2017			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Derivative assets (net)	$ —	$ 12,263	$ —	$ 12,263
Total net assets	$ —	$ 12,263	$ —	$ 12,263

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2016 (in thousands):

	Fair Value Measurements at December 31, 2016			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Derivative assets (net)	$ —	$ 6,436	$ —	$ 6,436
Total net assets	$ —	$ 6,436	$ —	$ 6,436

As of June 30, 2017, and December 31, 2016, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of ASC Topic 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. We periodically review oil and natural gas properties for impairment when facts and circumstances indicate that their carrying values may not be recoverable.

A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 8, "Asset Retirement Obligation."

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The following table summarizes the non-recurring fair value measurements of our assets as of June 30, 2017 (in thousands):

	Fair Value Measurements at June 30, 2017		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment(a)	$ —	$ —	$ 7,277
Total net assets	$ —	$ —	$ 7,277

(a) During the six months ended June 30, 2017, we recorded a non-cash impairment charge of $4.7 million to impair our producing oil and natural gas properties acquired in the Production Acquisition. The carrying values of the impaired proved properties were reduced to a fair value of $7.3 million, estimated using inputs characteristic of a Level 3 fair value measurement.

The following table summarizes the non-recurring fair value measurements of our assets as of December 31, 2016 (in thousands):

	Fair Value Measurements at December 31, 2016		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment(a)	$ —	$ —	$ 10,733
Acquisitions(b)	—	—	24,184
Total net assets	$ —	$ —	$ 34,917

(a) During the year ended December 31, 2016, we recorded a non-cash impairment charge of $7.6 million to impair our producing oil and natural gas properties in Texas and Louisiana (acquired prior to the Eagle Ford Acquisition) and in Oklahoma. The carrying values of the impaired proved properties were reduced to a fair value of $10.7 million, estimated using inputs characteristic of a Level 3 fair value measurement.

(b) During the year ended December 31, 2016, we acquired oil and natural gas properties with a fair value of $24.2 million. See Note 3. “Acquisitions and Divestitures” for fair value allocation.

The fair values of oil and natural gas properties were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership’s management at the time of the valuation and are the most sensitive and subject to change.

Fair Value of Financial Instruments

Fair value guidance requires certain fair value disclosures, such as those on our debt and derivatives, to be presented in both interim and annual reports. The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below.

Credit Agreement – We believe that the carrying value of long-term debt for our Credit Agreement (defined below) approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. Our Credit

Agreement is discussed further in Note 6, “Long-Term Debt.”

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate derivatives as of June 30, 2017. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

Embedded Derivative – The Partnership entered into a contract for the sale of preferred units in October 2015 which contained provisions that were required to be bifurcated from the contract and valued as a derivative. The embedded derivative was valued through the use of a Monte Carlo model which utilized observable inputs, the Partnership’s unit prices at various timelines, as well as unobservable inputs related to the weighted probabilities of certain redemption scenarios. We therefore classified the fair value measurements of our embedded derivative as Level 3 inputs. In November 2016, we completed a public offering and private placement

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of common units. As a result of these equity issuances, the Class B conversion rate was fixed and the provisions that required the bifurcation were removed. At that time, the fair value of the derivative was transferred to mezzanine equity.

The following table sets forth a reconciliation of changes in the fair value of the Partnership's embedded derivative classified as Level 3 in the fair value hierarchy for the year ended December 31, 2016 (in thousands):

	December 31, 2016
Beginning balance	$ (193,077)
Gain on embedded derivative	47,794
Transfer to mezzanine equity	145,283
Ending balance	$ —
Loss included in earnings related to derivatives still held as of December 31, 2016	$ —

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, “Derivatives and Hedging,” all derivative instruments are recorded on the condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have not elected to designate any of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included in natural gas sales and oil sales in the condensed consolidated statements of operations.

As of June 30, 2017, we had the following derivative contracts in place for the periods indicated, all of which are accounted for as mark-to-market activities:

Fixed Price Basis Swaps–West Texas Intermediate (WTI)

	March 31, Volume (Bbls)	Average Price	June 30, Volume (Bbls)	Average Price	September 30, Volume (Bbls)	Average Price	December 31, Volume (Bbls)	Average Price	Total Volume (Bbls)	Average Price
2017	—	$ —	—	$ —	87,304	$ 61.42	81,702	$ 61.55	169,006	$ 61.48
2018	88,854	$ 60.82	83,976	$ 60.90	79,683	$ 60.96	75,864	$ 61.02	328,377	$ 60.92
2019	78,667	$ 61.48	75,326	$ 61.53	72,279	$ 61.57	69,480	$ 61.61	295,752	$ 61.54
2020	66,914	$ 53.50	64,477	$ 53.50	62,251	$ 53.50	60,224	$ 53.50	253,866	$ 53.50
									1,047,001	

Fixed Price Swaps—NYMEX (Henry Hub)

	March 31, Volume (MMBtu)	Average Price	June 30, Volume (MMBtu)	Average Price	September 30, Volume (MMBtu)	Average Price	December 31, Volume (MMBtu)	Average Price	Total Volume (MMBtu)	Average Price
2017	—	$ —	—	$ —	271,368	$ 5.45	257,234	$ 5.45	528,602	$ 5.45
2018	260,841	$ 3.18	248,018	$ 3.18	235,810	$ 3.18	225,208	$ 3.18	969,877	$ 3.18
2019	224,303	$ 3.10	214,186	$ 3.10	205,533	$ 3.10	197,455	$ 3.10	841,477	$ 3.10
2020	188,696	$ 2.85	176,946	$ 2.85	170,637	$ 2.85	164,747	$ 2.85	701,026	$ 2.85
									3,040,982	

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The following table sets forth a reconciliation of the changes in fair value of the Partnership's commodity derivatives for the six months ended June 30, 2017 and the year ended December 31, 2016 (in thousands):

	June 30, 2017	December 31, 2016
Beginning fair value of commodity derivatives	$ 6,436	$ 31,018
Net gains (losses) on crude oil derivatives	8,543	(8,355)
Net gains on natural gas derivatives	725	1,116
Net settlements on derivative contracts:		
Crude oil	(2,144)	(13,622)
Natural gas	(1,297)	(6,919)
Net premiums on derivative contracts	—	3,198
Ending fair value of commodity derivatives	$ 12,263	$ 6,436

The effect of derivative instruments on our condensed consolidated statements of operations was as follows (in thousands):

		Amount of Gain (Loss) in Income			
		Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Type	Location of Gain (Loss) in Income	2017	2016	2017	2016
Commodity – Oil Hedges	Oil sales	$ 3,048	$ (6,260)	$ 8,543	$ (3,568)
Commodity – Gas Hedges	Natural gas sales	165	(1,466)	725	(168)
		$ 3,213	$ (7,726)	$ 9,268	$ (3,736)

Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently contracted with four counterparties. We generally execute commodity derivative instruments under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments. As of June 30, 2017, and December 31, 2016, the impact of non-performance credit risk on the valuation of our derivative instruments was not significant.

Embedded Derivative

The Partnership entered into a contract for the sale of preferred units in October 2015 which contained provisions that were required to be bifurcated from the contract and valued as a derivative. The embedded derivative was valued through the use of a Monte Carlo model which utilized observable inputs, the Partnership's unit prices at various timelines, as well as unobservable inputs related to the weighted probabilities of certain redemption scenarios. In November 2016, we completed a public offering and private placement of common units. As a result of these equity issuances, the Class B conversion rate was determined and the provisions that were required to bifurcate were removed. At that time, the fair value of the derivative was transferred to mezzanine equity.

The following table sets forth a reconciliation of the changes in fair value of the Partnership's embedded derivative for the year ended December 31, 2016 (in thousands):

	December 31, 2016
Beginning fair value of embedded derivative	$ (193,077)
Gain on embedded derivative	47,794
Transfer to mezzanine equity	145,283
Ending fair value of embedded derivative	$ —

6. LONG-TERM DEBT

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (the "Credit Agreement"). The Credit Agreement provides a maximum commitment of $500.0 million and has a maturity date of March 31, 2020. Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that we own as well as various security and pledge agreements among the Partnership and certain of its subsidiaries and the administrative agent.

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The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of $15.0 million which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was $200.0 million. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is equal to the rolling four quarter EBITDA of our midstream operations multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders. As of June 30, 2017, the borrowing base under the Credit Agreement was $215.6 million, with an elected commitment amount of $200.0 million.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank rate (“LIBOR”) plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) a domestic bank rate (“ABR”) plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus (iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

- current assets to current liabilities of at least 1.0 to 1.0 at all times;
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the adjusted EBITDA of our midstream operations equals or exceeds one-third of total Adjusted EBITDA or 4.0 to 1.0 if the adjusted EBITDA of our midstream operations is less than one-third of total adjusted EBITDA; and
- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At June 30, 2017, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance for any violation of a financial covenant from the lenders, but there is no assurance that such waivers would be granted.

Debt Issuance Costs

As of June 30, 2017, and December 31, 2016, our unamortized debt issuance costs were $1.4 million and $1.7 million, respectively. These costs are amortized to interest expense in our consolidated statements of operations over the life of our Credit Agreement. Amortization of debt issuance costs recorded during the three months ended June 30, 2017 and 2016 were $0.1 million.

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Amortization of debt issuance costs recorded during the six months ended June 30, 2017 and 2016 were $0.3 million and $0.2 million, respectively.

7. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

Gathering and transportation assets consist of the following (in thousands):

	June 30, 2017	December 31, 2016
Gathering and transportation assets		
Midstream assets	$ 176,195	$ 152,209
Less: Accumulated depreciation and amortization	(23,203)	(15,020)
Total gathering and transportation assets	$ 152,992	$ 137,189

Oil and natural gas properties consisted of the following (in thousands):

	June 30, 2017	December 31, 2016
Oil and natural gas properties and related equipment		
Property costs		
Proved property	$ 757,150	$ 758,366
Unproved property	54	46
Land	501	501
Total property costs	757,705	758,913
Materials and supplies	1,056	1,056
Total	758,761	759,969
Less: Accumulated depreciation, depletion, amortization and impairments	(685,112)	(674,338)
Oil and natural gas properties and equipment, net	$ 73,649	$ 85,631

Oil and Natural Gas Properties We follow the successful efforts method of accounting for our oil and natural gas production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties.

Depreciation, Depletion and Amortization. Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed reserves.

All other properties, including the gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, and up to 36 years for gathering facilities.

Depreciation, depletion, amortization and impairments consisted of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 2,877	$ 942	$ 6,111	$ 2,962
Depreciation, depletion and amortization of gathering and transportation-related assets	2,648	1,728	8,183	3,438
Amortization of intangible assets	3,412	3,459	6,824	6,917
Total Depreciation, depletion and amortization	8,937	6,129	21,118	13,317
Asset impairments	—	—	4,688	1,309
Total	$ 8,937	$ 6,129	$ 25,806	$ 14,626

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Impairment of Oil and Natural Gas Properties and Other Non-Current Assets. Oil and natural gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates are based upon reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Other significant inputs, besides reserves, used to determine the fair values of proved properties include estimates of: (i) future operating and development costs; (ii) future commodity prices; and (iii) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Cash flow estimates for impairment testing exclude derivative instruments.

For the three months ended June 30, 2017, we recorded no impairment charges. For the six months ended June 30, 2017, we recorded non-cash charges of $4.7 million, to impair certain producing oil and natural gas properties in Texas acquired as part of the Production Acquisition. For the three months ended June 30, 2016, we did not record impairment charges. For the six months ended June 30, 2016, we recorded non-cash charges of $1.3 million, to impair our producing oil and natural gas properties in Texas and Louisiana acquired prior to the Eagle Ford acquisition.

Asset Retirement Obligation. As described in Note 8, estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved developed reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Exploration and Dry Hole Costs. Exploration and dry hole costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs and the impairment, amortization and abandonment associated with leases on our unproved properties. All such costs on oil and natural gas properties relating to unsuccessful exploratory wells are charged to expense as incurred. We recorded no exploration or dry hole costs for the six months ended June 30, 2017 or 2016.

8. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost ("ARC") is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities or gathering and transportation assets. Subsequently, the ARC is depreciated using the units-of-production method for production assets and the straight-line method for midstream assets. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells, and decommissioning of oil and natural gas gathering and other facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance.

The following table is a reconciliation of the ARO (in thousands):

	June 30, 2017	December 31, 2016
Asset retirement obligation, beginning balance	$ 13,579	$ 20,364
Liabilities added from acquisitions	195	912
Sold	—	(6,291)
Revisions to cost estimates	—	(2,399)
Settlements	(45)	(134)
Accretion expense	498	1,127
Asset retirement obligation, ending balance	$ 14,227	$ 13,579

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. During the six months ended June 30, 2017, and the year ended December 31, 2016, there were no significant expenditures for abandonments and as of June 30, 2017 and December 31, 2016, there were no assets legally restricted for purposes of settling existing AROs. During 2016, obligations were sold as part of the Mid-Continent Divestiture that significantly lowered the Partnership's future abandonment obligations. Additional reductions in future abandonment obligations are expected in the third quarter 2017 as a result of the Non-Operated Production Divestiture, Oklahoma Production Divestiture and expected Texas Production Divestiture.

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9. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance includes $178.9 million related to the gathering agreement with Sanchez Energy that was entered into as part of the acquisition of the Western Catarina gathering system ("Western Catarina Midstream"). Pursuant to the 15-year agreement, Sanchez Energy tenders all of its crude petroleum, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15-year life of the agreement. During 2016, the intangible asset balance was reduced by $0.2 million due to marketing contracts from the 2007 Newfield acquisition which were included in the Mid-Continent Divestiture.

Amortization expense for the six months ended June 30, 2017 and 2016 was $6.8 million and $6.9 million, respectively. These costs are amortized to depreciation, depletion, and amortization expense in our consolidated statement of operations. Intangible assets as of June 30, 2017, and December 31, 2016 are detailed below (in thousands):

	June 30, 2017	December 31, 2016
Beginning balance	$ 185,766	$ 199,741
Disposals	—	(219)
Amortization	(6,824)	(13,756)
Ending balance	$ 178,942	$ 185,766

10. INVESTMENTS

On July 5, 2016, the Partnership purchased a 50% membership interest in Carnero Gathering from SN Midstream for an initial payment of approximately $37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million as of the date of the acquisition. The remaining 50% membership interests of Carnero Gathering are owned by an affiliate of Targa. During the six months ended June 30, 2017, the Partnership made approximately $4.8 million of capital contributions to the joint venture. Prior to the sale, SN Midstream had invested approximately $26.0 million in the Carnero Gathering joint venture. The fair value of the intangible asset for the contractual customer relationship related to Carnero Gathering was valued at approximately $13.0 million. This amount is being amortized over the contract term of fifteen years and decrease earnings from Carnero Gathering. As part of the Carnero Gathering Transaction, the Partnership is required to pay SN Midstream a monthly earnout based upon gas received at Carnero Gathering's receipt points from SN Catarina and gas delivered by other producers and processing by Carnero Processing. This earnout is considered as contingent consideration and its estimated fair value of $4.0 million was recorded on the balance sheet as a deferred liability as of June 30, 2017. No earnout payments were made in the three or six months ended June 30, 2017.

As of June 30, 2017, the Partnership had paid approximately $45.6 million for the Carnero Gathering Transaction related to the initial purchase price, acquisition costs and contributed capital to date. The Partnership has accounted for this investment as an equity method investment. Targa is the operator of the joint venture and has significant influence with respect to the normal day-to-day construction and operating decisions. We have included the investment balance in the "Equity investments" caption in our Condensed Consolidated Balance Sheet. For the six months ended June 30, 2017, the Partnership recorded earnings of approximately $2.6 million in equity investments from Carnero Gathering, which was offset by approximately $0.4 million related to the amortization of the contractual customer intangible asset. For the three months ended June 30, 2017, the Partnership recorded earnings of approximately $1.4 million in equity investments from Carnero Gathering, which was offset by approximately $0.2 million related to the amortization of the contractual customer intangible asset. We have included these equity method earnings in the "Earnings from equity investments" line within the Condensed Consolidated Statements of Operations. Cash distributions of $3.7 million were received during the six months ended June 30, 2017.

On November 22, 2016, the Partnership purchased a 50% membership interest in Carnero Processing from SN Midstream for an initial payment of approximately $55.5 million and the assumption of remaining capital commitments to Carnero Processing, estimated at approximately $24.5 million as of the date of the acquisition. The remaining 50% membership interests of Carnero Processing are owned by an affiliate of Targa. During the six months ended June 30, 2017, the Partnership made $3.5 million of capital contributions to the joint venture. Prior to the sale, SN Midstream had invested approximately $48.0 million in the Carnero Processing joint venture.

As of June 30, 2017, the Partnership had paid approximately $70.0 million for the Carnero Processing transaction related to the initial payment, acquisition costs and contributed capital. The Partnership has accounted for this investment as an equity method investment. Targa is the operator of the joint venture and has significant influence with respect to the normal day-to-day construction

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and operating decisions. We have included the investment balance in the "Equity investments" caption in our consolidated balance sheet. The Partnership recorded expenses of approximately $0.6 million in the "Earnings from equity investments" line within our consolidated statements of operations for the six months ended June 30, 2017 and $0.2 million for the three months ended June 30, 2017.

Summarized financial information of unconsolidated entities is as follows (in thousands):

	Six Months Ended June 30, 2017
Sales	$ 15,222
Total expenses	10,960
Net income	$ 4,262

	June 30, 2017	December 31, 2016
Current assets	$ 21,780	$ 27,779
Noncurrent assets	183,371	152,112
Current liabilities	12,078	16,577

11. COMMITMENTS AND CONTINGENCIES

As part of the Carnero Gathering Transaction, the Partnership is required to pay SN Midstream a monthly earnout based upon gas received at Carnero Gathering's receipt points from SN Catarina and gas delivered and processed at Carnero Processing by other producers which began at the end of the second quarter 2017. This earnout has an approximate value of $4.0 million and was recorded on the balance sheet as a deferred liability as of June 30, 2017. We did not have any other material commitments and contingencies and no payments were made as of June 30, 2017.

12. RELATED PARTY TRANSACTIONS

We are controlled by our general partner. The sole member of our general partner is Manager, which has no officers. In May 2014, we entered into the Services Agreement with Manager pursuant to which Manager provides services that we require to operate our business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, professionals, acquisition, disposition and financing services. In connection with providing services under the Services Agreement, Manager receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Each of these fees, not including the reimbursement of costs, is paid in cash unless Manager elects for such fee to be paid in our equity. The Services Agreement has a ten-year term and will be automatically renewed for additional one-year terms unless either Manager or the Partnership provides notice of termination to the other with at least 180 days' notice. During the six months ended June 30, 2017, we expensed approximately $4.4 million to Manager pursuant to the Services Agreement.

Manager utilizes Sanchez Oil & Gas Corporation ("SOG"), to provide the services under the Services Agreement. In May 2014, we entered into a Contract Operating Agreement with SOG pursuant to which SOG either provides services to operate, develop and produce our oil and natural gas properties or engages a third-party operator to do so, other than with respect to our properties in the Mid-Continent Region. We also have entered into the Geophysical Seismic Data Use License Agreement with SOG pursuant to which SOG provides us a non-exclusive, royalty-free license to use seismic, geophysical and geological information relating to our oil and natural gas properties that is proprietary to SOG and not restricted by agreements that SOG has with landowners or seismic data vendors.

SOG, headquartered in Houston, Texas, is a private full-service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. The Chairman of the board of directors of our general partner, the President and Chief Operating Officer of our general partner, Eduardo A. Sanchez, one of our directors, along with their immediate family members Ana Lee Sanchez Jacobs and Antonio R. Sanchez, Jr., collectively, either directly or indirectly, own a majority of the equity interests of SOG. In addition, Antonio R. Sanchez, Jr. is a member of the board of directors of SOG, and such other individuals, as well as Ana Lee Sanchez Jacobs, are officers of SOG.

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In October 2015, the Partnership entered into a Firm Gathering and Processing Agreement with Sanchez Energy for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas is dedicated for gathering by Catarina Midstream, LLC (the "Gathering Agreement"). In addition, for the first five years of the Gathering Agreement, SN Catarina will be required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. On June 30, 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by SN Catarina based on water that is delivered through the gathering system through March 31, 2018.

As of June 30, 2017, and December 31, 2016, the Partnership had a net receivable from related parties of $4.8 million and $6.0 million, respectively, which are included in "Accounts receivable – related entities" in the condensed consolidated balance sheets. As of June 30, 2017, and December 31, 2016, the Partnership also had a net payable to related parties of $14.8 million and $7.0 million, respectively. The net receivables/payable as of June 30, 2017, and December 31, 2016 consist primarily of revenues receivable from oil and natural gas production and transportation, offset by costs associated with that production and transportation, development of gathering and transportation assets and obligations for general and administrative costs.

In July 2016, we acquired 50% of the outstanding membership interests in Carnero Gathering from SN Midstream for cash consideration of approximately $37.0 million, and the assumption of approximately $7.4 million of remaining capital commitments to Carnero Gathering. In addition, the Partnership is required to pay SN Midstream a monthly earnout based on gas received from SN Catarina at Carnero Gathering's receipt points, as well as gas delivered and processed at the Raptor Gas Processing Facility for other producers. The remaining 50% of the membership interests are owned by an affiliate of Targa. Carnero Gathering operates a gas gathering pipeline in the Western Eagle Ford in South Texas that interconnects with the Raptor Gas Processing Facility. The Partnership made capital contributions to Carnero Gathering totaling $8.1 million between July 5, 2016, and June 30, 2017. See further discussion of the transaction in Note 3, "Acquisitions and Divestitures."

In October 2016, the Partnership entered into a Purchase and Sale Agreement (the "Lease Option Purchase Agreement") with Sanchez Energy and SN Terminal, LLC (the "SNT"), pursuant to which SNT granted and conveyed to the Partnership an option to acquire a ground lease (the "Lease Option") to which SNT is a party for a tract of land leased from the Calhoun Port Authority in Point Comfort, Texas. In addition, if Sanchez Energy or any of its affiliates have entered into an option to engage in the construction of or participation in a Project (as defined below) and/or receive the benefit of an acreage dedication from an affiliate of the Sanchez Energy relating to a Project, then such option and/or acreage dedication will also be assigned to us, if we exercise the Lease Option. The Partnership will pay SNT $1.00 if the Lease Option is exercised, along with $250,000 if the Partnership or any of its affiliates elects to construct, own or operate a marine crude storage terminal on or within five miles of the Point Comfort lease or participates as an investor in the same, within five miles thereof (a "Project").

In November 2016, in conjunction with our public offering of common units, the Partnership entered into a Common Unit Purchase Agreement with SN UR Holdings, LLC (the "Purchaser"), a wholly-owned subsidiary of Sanchez Energy, whereby we issued to the Purchaser 2,272,727 common units for proceeds of approximately $25.0 million. See further discussion of the transaction in Note 3, "Acquisitions and Divestitures."

In November 2016, we acquired 50% of the outstanding membership interests in Carnero Processing from SN Midstream for cash consideration approximately $55.5 million and the assumption of approximately $24.5 million of remaining capital commitments to Carnero Processing. The Partnership made capital contributions to Carnero Processing totaling $14.1 million between November 22, 2016 and June 30, 2017. Also in November 2016, the Partnership consummated a Purchase and Sale Agreement with SN Cotulla Assets, LLC and SN Palmetto, LLC, each a wholly-owned subsidiary of Sanchez Energy, to purchase working interest in 23 producing Eagle Ford Shale wellbores located in Dimmit and Zavala counties in South Texas as well as escalating working interests in an additional 11 producing wellbores in the Palmetto Field in Gonzales, Texas for approximately $24.2 million. See further discussion of the transactions in Note 3, “Acquisitions and Divestitures.”

Sanchez Energy is an independent exploration and production company focused on the acquisition and development of U.S. onshore unconventional oil and natural gas resources, with a current focus on the Eagle Ford Shale in South Texas where it has assembled approximately 356,000 net acres. The Chairman of the board of directors of our general partner, Antonio R. Sanchez, III, is Sanchez Energy’s Chief Executive Officer and a member of its board of directors. A member of the board of directors of our general partner, Eduardo A. Sanchez, is the President of Sanchez Energy. The President and Chief Operating Officer of our general partner, Patricio D. Sanchez, who is also a member of the board of directors of our general partner, is an Executive Vice President of Sanchez Energy. Antonio R. Sanchez, Jr., the father of Antonio R. Sanchez, III, Eduardo A. Sanchez, and Patricio D. Sanchez, is the Executive Chairman of the board of directors of Sanchez Energy. Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, Patricio D. Sanchez and Eduardo A. Sanchez beneficially own approximately 7.4%, 3.1%, 0.8% and 1.6%, respectively, of Sanchez Energy’s shares outstanding as of June 30, 2017. Sanchez Energy indirectly, through one of its wholly owned subsidiaries, beneficially owns approximately 15.6% of the outstanding common units of SNMP.

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13. UNIT-BASED COMPENSATION

The Sanchez Midstream Partners LP Long-Term Incentive Plan (the “LTIP”) allows for restricted common unit grants. Restricted common unit activity under the LTIP during the period is presented in the following table:

	Number of Restricted Units	Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2016	219,144	$ 14.22
Granted	215,814	14.83
Vested	(44,583)	15.70
Outstanding at June 30, 2017	390,375	$ 14.39

In March 2017, the Partnership issued 171,231 restricted common units pursuant to the LTIP to executives of the Partnership’s general partner that vest on the first anniversary of grant. In April 2017, the Partnership issued 44,583 restricted common units pursuant to the LTIP to certain directors of the Partnership’s general partner that vested immediately on the date of grant. The unit-based compensation expense for the award was based on the fair value on the day before the date of grant. During the year ended December 31, 2016, the Partnership issued 67,627 restricted common units pursuant to the LTIP to certain directors of the Partnership’s general partner that vested immediately on the date of the grant. The unit-based compensation expense for the award was based on the fair value on the day before the date of grant.

As of June 30, 2017, 1,591,019 common units remain available for future issuance to participants under the LTIP.

14. DISTRIBUTIONS TO UNITHOLDERS

The table below reflects the payment of cash distributions on common units related to the six months ended June 30, 2017, and the year ended December 31, 2016.

Three Months Ended	Distribution Per Unit	Date of Declaration	Date of Record	Date of Distribution
June 30, 2016	$ 0.4183	August 10, 2016	August 22, 2016	August 31, 2016
September 30, 2016	$ 0.4246	October 31, 2016	November 10, 2016	November 30, 2016
December 31, 2016	$ 0.4310	February 9, 2017	February 20, 2017	February 28, 2017
March 31, 2017	$ 0.4375	May 10, 2017	May 22, 2017	May 31, 2017
June 30, 2017	$ 0.4441	August 9, 2017	August 22, 2017	August 31, 2017

The table below reflects the payment of distributions on Class B preferred units related to the six months ended June 30, 2017, and the year ended December 31, 2016.

Three Months Ended	Distribution Per Unit	Date of Declaration	Date of Record	Date of Distribution

June 30, 2016	$ 0.4500	August 10, 2016	August 22, 2016	August 31, 2016
September 30, 2016	$ 0.4500	October 31, 2016	November 10, 2016	November 30, 2016
December 31, 2016 (a)	$ 0.2258	February 9, 2017	February 20, 2017	February 28, 2017
March 31, 2017 (b)	$ 0.2258	May 10, 2017	May 22, 2017	May 31, 2017
June 30, 2017	$ 0.28225	August 9, 2017	August 22, 2017	August 31, 2017

(a) The Partnership elected to pay the fourth quarter 2016 distribution on the Class B preferred units in part cash and, with the consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B preferred units). Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B preferred unit and an aggregate distribution of 208,594 common units, each paid on February 28, 2017 to holders of record on February 20, 2017.

(b) The Partnership elected to pay the first quarter 2017 distribution on the Class B preferred units in part cash and, with the consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B preferred units). Accordingly, the Partnership declared a cash distribution of $0.2258 per Class B preferred unit and an aggregate distribution of 184,697 common units, each payable on May 31, 2017 to holders of record on May 22, 2017.

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15. PARTNERS' CAPITAL

Outstanding Units

As of June 30, 2017, we had 31,000,887 Class B Preferred Units outstanding, and 14,606,028 common units outstanding.

Common Unit Issuances

In connection with providing services under the Services Agreement for the first quarter 2017, the Partnership issued 139,110 common units to SP Holdings, LLC on June 30, 2017. In connection with providing services under the Services Agreement for the third and fourth quarters of 2016, the Partnership issued 170,750 and 154,737 common units, respectively, to SP Holdings, LLC on March 6, 2017. See Note 12, "Related Party Transactions" for additional information related to the Services Agreement.

The Partnership elected to pay the first quarter 2017 distribution on the Class B preferred units in part cash and, with the consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B preferred units). Accordingly, the Partnership issued 184,697 common units on May 22, 2017, to the holder of Class B preferred units.

In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately $1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015 as updated by that certain prospectus supplement filed with the SEC on April 6, 2017 (the "Shelf Registration Statement"). The Shelf Registration Statement allows the Partnership to sell up to $50.0 million of common units at-the-market to fund general limited partnership purposes, including possible acquisitions. Proceeds from the at-the-market equity issuance were used for general limited partnership purposes.

The Partnership elected to pay the fourth quarter 2016 distribution on the Class B preferred units in part cash and, with the consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B preferred units). Accordingly, the Partnership issued 208,594 common units on February 20, 2017 to the holder of Class B preferred units.

In November 2016, we completed a public offering and private placement of common units. The public offering consisted of 6,745,107 common units (which includes partial exercise of the underwriters' overallotment of 194,305 common units) for net proceeds of approximately $69.7 million, after deducting customary offering expenses. The private placement consisted of 2,272,727 common units issued to Sanchez Energy for net proceeds of approximately $25.0 million.

In March 2016, the Partnership converted all remaining outstanding Class A Preferred Units into common units of the Partnership on a one for one basis, adjusted for the 1-for-10 unit split in August 2015.

Class B Preferred Unit Offering

On October 14, 2015, pursuant to that certain Class B Preferred Unit Purchase Agreement dated September 25, 2015 between the Partnership and Stonepeak Catarina Holdings LLC ("Stonepeak"), the Partnership sold and Stonepeak purchased 19,444,445 of the Partnership's newly created Class B Preferred Units (the "Class B Preferred Units") in a privately negotiated transaction for an aggregate cash purchase price of $18.00 per Class B Preferred Unit, which resulted in gross proceeds to the Partnership of approximately $350.0 million. The Partnership used the net proceeds to pay a portion of the consideration for the acquisition of Western Catarina Midstream, along with the payment to Stonepeak of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

Under the terms of our partnership agreement, holders of the Class B Preferred Units received a quarterly distribution, at the election of the board of directors of our general partner, of 10.0% per annum if paid in full in cash or 12.0% per annum if paid in part cash (8.0% per annum) and in part paid-in-kind units (4.0% per annum). Distributions are to be paid on or about the last day of each of February, May, August and November after the end of each quarter.

In accordance with the partnership agreement, on December 6, 2016, we issued an additional 9,851,996 Class B preferred units to Stonepeak. On January 25, 2017, the Partnership and Stonepeak entered into a Settlement Agreement and Mutual Release (the “Settlement Agreement”) to settle a dispute arising from the calculation of an adjustment to the number of Class B Preferred Units pursuant to Section 5.10(g) of the Second Amended and Restated Agreement of Limited Partnership of the Partnership (the “Amended Partnership Agreement”). Pursuant to the Settlement Agreement, and in accordance with Section 5.4 of the Amended Partnership Agreement, the Partnership issued 1,704,446 Class B Preferred Units to Stonepeak in a privately negotiated transaction as partial consideration for the Settlement Agreement, with the “Class B Preferred Unit Price” being established at $11.29 per Class B Preferred Unit. Pursuant to the terms of the Amended Partnership Agreement, the Class B Preferred Units are convertible at any time, at the option of Stonepeak, into common units of the Partnership, subject to the requirement to convert a minimum of $17.5 million of Class B

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Preferred Units. The issuance of the Class B Preferred Units pursuant to the Settlement Agreement was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933 pursuant to Section 4(a)(2) thereof.

The Class B Preferred Units are accounted for as mezzanine equity in the consolidated balance sheet consisting of the following (in thousands):

	June 30, 2017	December 31, 2016
Mezzanine equity beginning balance	$ 342,991	$ 172,111
Discount	—	(87)
Amortization of discount	837	23,477
Distributions	18,375	39,375
Distributions paid	(19,250)	(37,168)
Transfer embedded derivative to Class B	—	145,283
Total mezzanine equity	$ 342,953	$ 342,991

Earnings per Unit

Net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income (loss) based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. The two-class method dictates that net income (loss) for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income (loss) be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income (loss) as if all of the net income for the period had been distributed in accordance with the partnership agreement. Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income (loss) per unit. Undistributed income (loss) is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units based on provisions of the partnership agreement. Undistributed losses are not allocated to unvested restricted unit awards as they do not participate in net losses. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

Our general partner does not have an economic interest in the Partnership and, therefore, does not participate in the Partnership's net income. The following table presents the weighted average basic and diluted units outstanding for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Common units - Basic and Diluted	13,939,993	3,935,297	13,671,557	3,333,482
Weighted Common units - Basic and Diluted	13,939,993	3,935,297	13,671,557	3,333,482

At June 30, 2017, we had 390,375 common units that were restricted unvested common units granted and outstanding. No losses were allocated to participating restricted unvested units because such securities do not have a contractual obligation to share in the Partnership's losses.

The following table presents our basic and diluted loss per unit for the three months ended June 30, 2017 (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss to be allocated	$ (8,624)	$ (8,624)
Basic and diluted loss per unit		$ (0.62)

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The following table presents our basic and diluted loss per unit for the three months ended June 30, 2016 (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss to be allocated	$ (17,207)	$ (17,207)
Basic and diluted loss per unit		$ (4.37)

The following table presents our basic and diluted loss per unit for the six months ended June 30, 2017 (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss to be allocated	$ (26,312)	$ (26,312)
Basic and diluted loss per unit		$ (1.92)

The following table presents our basic and diluted loss per unit for the six months ended June 30, 2016 (in thousands, except for per unit amounts):

	Total	Common Units
Assumed net loss to be allocated	$ (27,947)	$ (27,947)
Basic and diluted loss per unit		$ (8.38)

16. REPORTING SEGMENTS

“Midstream” and “Production” best describe the operating segments of the businesses that we separately report. The factors used to identify these reporting segments are based on the nature of the operations that are undertaken by each segment. The Midstream segment operates the gathering, processing and transportation of crude oil, natural gas and NGLs. The Production segment operates to produce crude oil and natural gas. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the Partnership because they are the segments (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Partnership’s chief operating decision maker to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available. Operating segments are evaluated for their contribution to the Partnership's consolidated results based on operating income, which is defined as segment operating revenues less expenses.

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The following tables set forth our segment information for the periods indicated (in thousands):

	Three Months Ended June 30, 2017		
	Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 2,252	$ —	$ 2,252
Oil sales	8,109	—	8,109
Natural gas liquids sales	492	—	492
Gathering and transportation sales	—	14,176	14,176
Total operating revenues	10,853	14,176	25,029
Operating expenses:			
Lease operating expenses	3,648	233	3,881
Transportation operating expenses	—	3,032	3,032
Cost of sales	40	—	40
Production taxes	353	—	353
General and administrative	4,892	1,461	6,353
Unit-based compensation expense	780	—	780
Depreciation, depletion and amortization	2,924	6,013	8,937
Accretion expense	172	68	240
Total operating expenses	12,809	10,807	23,616
Operating income (loss)	$ (1,956)	$ 3,369	$ 1,413

	Three Months Ended June 30, 2016		
	Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 600	$ —	$ 600
Oil sales	(2,756)	—	(2,756)
Natural gas liquids sales	244	—	244
Gathering and transportation sales	—	14,258	14,258
Total operating revenues	(1,912)	14,258	12,346
Operating expenses:			
Lease operating expenses	3,905	273	4,178
Transportation operating expenses	—	3,014	3,014
Cost of sales	63	—	63
Production taxes	326	—	326
General and administrative	3,550	1,428	4,978
Unit-based compensation expense	1,091	—	1,091
Depreciation, depletion and amortization	1,035	5,094	6,129
Accretion expense	253	62	315
Total operating expenses	10,223	9,871	20,094

Operating income (loss)	$ (12,135)	$ 4,387	$ (7,748)

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	Six Months Ended June 30, 2017		
	Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 5,031	$ —	$ 5,031
Oil sales	19,459	—	19,459
Natural gas liquids sales	959	—	959
Gathering and transportation sales	—	25,387	25,387
Total operating revenues	25,449	25,387	50,836
Operating expenses:			
Lease operating expenses	8,372	492	8,864
Transportation operating expenses	—	6,328	6,328
Cost of sales	77	—	77
Production taxes	826	—	826
General and administrative	8,996	2,966	11,962
Unit compensation expense	1,320	—	1,320
Depreciation, depletion and amortization	6,205	14,913	21,118
Asset impairments	4,688	—	4,688
Accretion expense	364	134	498
Total operating expenses	30,848	24,833	55,681
Operating income (loss)	$ (5,399)	$ 554	$ (4,845)

	Six Months Ended June 30, 2016		
	Production	Midstream	Total
Operating revenues			
Natural gas sales	$ 4,275	$ —	$ 4,275
Oil sales	2,587	—	2,587
Natural gas liquids sales	520	—	520
Gathering and transportation sales	—	28,133	28,133
Total operating revenues	7,382	28,133	35,515
Operating expenses:			
Lease operating expenses	8,780	371	9,151
Transportation operating expenses	—	6,068	6,068
Cost of sales	193	—	193
Production taxes	547	—	547
General and administrative	7,984	2,713	10,697
Unit-based compensation expense	1,529	—	1,529
Depreciation, depletion and amortization	3,149	10,168	13,317
Asset impairments	1,309	—	1,309
Accretion expense	507	123	630
Total operating expenses	23,998	19,443	43,441
Operating income (loss)	$ (16,616)	$ 8,690	$ (7,926)

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The following table summarizes the total assets by operating segment as of June 30, 2017 and December 31, 2016 (in thousands):

	June 30, 2017	December 31, 2016
Segment Assets		
Production	$ 205,482	$ 207,219
Midstream	341,833	332,486
Total assets	$ 547,315	$ 539,705

17. VARIABLE INTEREST ENTITIES

As noted above in Note 10, "Investments," the Partnership acquired a 50% membership interest in Carnero Gathering from SN Midstream for an initial payment of approximately $37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million as of the date of the acquisition. The Partnership determined that the Carnero Gathering joint venture is more similar to a limited partnership than a corporation. Under the revised guidance of ASU 2015-02, a limited partnership or similar entity with equity at risk will not be a variable interest entity ("VIE") if a partner is able to exercise kick-out rights over the general partner(s) or is able to exercise substantive participating rights. We concluded that the Carnero Gathering joint venture is a VIE under the revised guidance because we cannot remove Targa as operator and we do not have substantive participating rights. In addition, Targa has the discretion to direct activities of the VIE regarding the risks associated with price, operations, and capital investment which have the most significant impact on the VIE's economic performance.

The Partnership's investment in Carnero Gathering represents a VIE that could expose the Partnership to losses. The amount of losses the Partnership could be exposed to from the Carnero Gathering joint venture is limited to the capital investment of approximately $47.6 million.

As of June 30, 2017, the Partnership had invested approximately $45.6 million in Carnero Gathering. As of June 30, 2017, no debt has been incurred by Carnero Gathering. We have included this VIE in the "Equity investments" long-term asset line on the balance sheet.

As noted above in Note 10, "Investments," the Partnership acquired a 50% membership interest in Carnero Processing from SN Midstream for an initial payment of approximately $55.5 million and the assumption of remaining capital commitments to Carnero Processing, estimated at approximately $24.5 million as of the date of the acquisition. The Partnership determined that the Carnero Processing joint venture is more similar to a limited partnership than a corporation. Under the revised guidance of ASU 2015-02, a limited partnership or similar entity with equity at risk will not be a VIE if a limited partner is able to exercise kick-out rights over the general partner(s) or is able to exercise substantive participating rights. We concluded that the Carnero Processing joint venture is a VIE under the revised guidance because we cannot remove Targa as operator and we do not have substantive participating rights. In addition, Targa has the discretion to direct activities of the VIE regarding the risks associated with price, operations, and capital investment which have the most significant impact on the VIE's economic performance.

Similar to the Partnership's investment in Carnero Gathering, the Partnership's investment in Carnero Processing represents a VIE that could expose the Partnership to losses. The amount of losses the Partnership could be exposed to from the Carnero Processing joint venture is limited to the capital investment of approximately $79.3 million.

As of June 30, 2017, the Partnership had invested approximately $70.0 million in Carnero Processing. As of June 30, 2017, no debt has been incurred by Carnero Processing. We have included this VIE in the "Equity investments" long-term asset line on the balance sheet.

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Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Partnership's maximum exposure to loss as of June 30, 2017 and December 31, 2016 (in thousands):

	June 30, 2017	December 31, 2016
Capital investments	$ 115,606	$ 107,320
Earnings in equity investments	3,934	2,301
Distributions received	(6,600)	(2,950)
Estimated earnout accrued	4,049	4,270
Equity in equity investments	$ 116,989	$ 110,941

	June 30, 2017	December 31, 2016
Equity in equity investments	$ 116,989	$ 110,941
Guarantees of capital investments	9,986	17,584
Maximum exposure to loss	$ 126,975	$ 128,525

18. SUBSEQUENT EVENTS

On August 9, 2017, the board of directors of our general partner declared a second quarter 2017 cash distribution on the Partnership's common units of $0.4441 per unit ($1.7764 per unit annualized) payable on August 31, 2017 to holders of record on August 22, 2017. The Partnership also declared a second quarter distribution on the Class B preferred units and elected to pay the distribution in cash. Accordingly, the Partnership declared a cash distribution of $0.28225 per Class B preferred unit payable on August 31, 2017 to holders of record on August 22, 2017.

On July 17, 2017, we closed the Oklahoma Production Divestiture pursuant to which we sold all of the Partnership's equity interests in the entities that owned our remaining operated Oklahoma production assets for cash consideration of $5.5 million. In addition, the buyer assumed all obligations relating to the assets arising after the closing date and all plugging and abandonment costs relating to the assets arising prior to the closing date.

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

The following discussion and analysis should be read in conjunction with the financial statements and the summary of significant accounting policies and notes included herein and in our most recent Annual Report on Form 10-K. The following discussion contains "Forward-Looking Statements" that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. Please read "Cautionary Note Regarding Forward-Looking Statements."

Overview

Sanchez Midstream Partners LP, a Delaware limited partnership ("SNMP," "we," "us," "our" or the "Partnership") (formerly Sanchez Production Partners LP), is a growth oriented publicly-traded limited partnership focused on the acquisition, development, ownership and operation of midstream and production assets in North America. We have entered into a shared services agreement (the "Services Agreement") with SP Holdings, LLC (the "Manager"), the sole member of our general partner, pursuant to which the Manager provides services that the Partnership requires to operate its business, including overhead, technical, administrative, marketing, accounting, operational, information systems, financial, compliance, insurance, acquisition, disposition and financing services. Our common units are currently listed on the NYSE American under the symbol "SNMP," and were traded under the symbol "SPP" prior to our recent name change.

Historically, our operations have consisted of the production of proved reserves located in the Cherokee Basin in Oklahoma and Kansas, the Woodford Shale in the Arkoma Basin in Oklahoma, the Central Kansas Uplift in Kansas, the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana. In October 2015, we consummated the acquisition of midstream assets in the Eagle Ford Shale from Sanchez Energy Corporation ("Sanchez Energy") and entered into a 15-year gathering and processing agreement with Sanchez Energy. We also commenced a process to sell our production assets in the Mid-Continent region. In July 2016, we sold a portion of our production assets in the Mid-Continent region and acquired a 50% equity interest in Carnero Gathering. In November 2016, we completed a public offering of approximately 6,745,107 common units (which includes exercise of the underwriters' option to purchase 194,305 common units) for net proceeds of approximately $69.7 million, after deducting customary offering expenses. Concurrent with the public offering, we completed a private placement of 2,272,727 common units representing limited partner interests for net proceeds of approximately $25.0 million. The combined proceeds were used to close the acquisition of a 50% equity interest in Carnero Processing, and the acquisition of working interest in 23 producing Eagle Ford Shale wellbores located in Dimmit and Zavala counties in South Texas and escalating working interests in an additional 11 producing wellbores in the Palmetto Field in Gonzales, Texas. In July 2017, we sold our equity interests in the entities that owned our remaining operated Oklahoma production assets for cash consideration of $5.5 million, subject to customary post-closing adjustments, and assumption by the buyer of certain plugging and abandonment costs. On June 30, 2017, we signed a purchase and sale agreement to sell certain oil and natural gas properties in Texas.

How We Evaluate our Operations

We evaluate our business on the basis of the following key measures:

- our throughput volumes on the gathering system;
- our operating expenses; and
- our Adjusted EBITDA, a non-GAAP financial measure (for a reconciliation of Adjusted EBITDA to the most comparable GAAP financial measure please read "—Non-GAAP Financial Measures–Adjusted EBITDA").

Throughput Volumes

Upon the acquisition of Western Catarina Midstream, our management began to analyze our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within the dedicated areas in order to maintain or increase throughput volumes on the Western Catarina Midstream. Our success in connecting additional wells is impacted by successful drilling activity by Sanchez Energy on the acreage dedicated to the Western Catarina Midstream, our ability to secure volumes from Sanchez Energy from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure.

Operating Expenses

Our management seeks to maximize Adjusted EBITDA, a non-GAAP financial measure, in part by minimizing operating expenses. These expenses are or will be comprised primarily of field operating costs (which generally consists of lease operating

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expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, among other items), compression expense, ad valorem taxes and other operating costs, some of which will be independent of our oil and natural gas production or the throughput volumes on the gathering system but fluctuate depending on the scale of our operations during a specific period.

Non-GAAP Financial Measures—Adjusted EBITDA

To supplement our financial results and guidance presented in accordance with U.S. generally accepted accounting principles ("GAAP"), we use Adjusted EBITDA, a non-GAAP financial measure, in this quarterly report. We believe that non-GAAP financial measures are helpful in understanding our past financial performance and potential future results, particularly in light of the effect of various transactions effected by us. We define Adjusted EBITDA as net income (loss) adjusted by: (i) interest (income) expense, net, which includes interest expense, interest expense net (gain) loss on interest rate derivative contracts, and interest (income); (ii) income tax expense (benefit); (iii) depreciation, depletion and amortization; (iv) asset impairments; (v) accretion expense; (vi) (gain) loss on sale of assets; (vii) unit-based compensation programs; (viii) unit-based asset management fees; (ix) distributions in excess of equity earnings; (x) (gain) loss on mark-to-market activities; (xi) commodity derivatives settlements applied to future positions; (xii) (gain) loss on embedded derivatives; and (xiii) acquisition and divestiture costs.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by the board of directors of our general partner) the distributions that we would expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support a quarterly distribution or any increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess: (i) the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and (iii) our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We believe that the presentation of Adjusted EBITDA provides useful information to investors in assessing our financial condition and results of operations. The GAAP measure most directly comparable to Adjusted EBITDA is net income. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income. Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income. Adjusted EBITDA should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following table sets forth a reconciliation of Adjusted EBITDA to net income (loss), its most directly comparable GAAP performance measure, for each of the periods presented (in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Net income (loss)	$ 559	$ (1,952)	$ (7,100)	$ 3,325
Adjusted by:				
Interest expense, net	1,896	1,103	3,779	2,002

Depreciation, depletion and amortization	8,937	6,129	21,118	13,317
Asset impairments	—	—	4,688	1,309
Accretion expense	240	315	498	630
Unit-based compensation expense	1,479	1,091	2,019	1,529
Unit-based asset management fees	2,345	1,627	4,375	2,912
Distributions in excess of equity earnings	803	—	1,771	—
(Gain) loss on mark-to-market activities	(1,347)	13,210	(5,827)	16,314
Gain on embedded derivatives	—	(6,898)	—	(13,192)
Acquisition and divestiture costs	424	—	553	—
Adjusted EBITDA	$ 15,336	$ 14,625	$ 25,874	$ 28,146

Significant Operational Factors

· Throughput. During the three months ended June 30, 2017, Sanchez Energy transported average daily production through the gathering system of approximately 11.5 MBbls/d of crude oil, 169.6 MMcf/d of natural gas and 16.9 MBbls/d of water. During the three months ended June 30, 2016, Sanchez Energy transported average daily production through the gathering system of approximately 14.1 MBbls/d of crude oil, 193.3 MMcf/d of natural gas and an insignificant amount of

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water. During the six months ended June 30, 2017, Sanchez Energy transported average daily production through the gathering system of approximately 11.4 MBbls/d of crude oil, 160.7 MMcf/d of natural gas and 8.5 MBbls/d of water. During the six months ended June 30, 2016, Sanchez Energy transported average daily production through the gathering system of approximately 14.0 MBbls/d of crude oil, 190.4 MMcf/d of natural gas and an insignificant amount of water.

- Production. Our production for the three months ended June 30, 2017, was 290 MBOE, or an average of 3,187 BOE per day, compared with approximately 304 MBOE, or an average of 3,335 BOE per day, for the three months ended June 30, 2016. Our production for the six months ended June 30, 2017, was 600 MBOE, or an average of 3,315 BOE per day, compared with approximately 607 MBOE, or an average of 3,334 BOE per day, for the six months ended June 30, 2016.
- Capital Expenditures. For the three months ended June 30, 2017, we spent approximately $10.9 million in capital expenditures, consisting of $9.8 million related to the development of a pipeline off the tail of the Raptor Processing Facility and $1.1 million related to the development of Western Catarina Midstream. For the three months ended June 30, 2016, we spent approximately $1.2 million in capital expenditures, related to the development of Western Catarina Midstream. For the six months ended June 30, 2017, we spent approximately $24.0 million in capital expenditures, consisting of $21.7 million related to the development of the Raptor Gas Processing Facility and $2.3 million related to the development of Western Catarina Midstream. For the six months ended June 30, 2016, we spent approximately $2.3 million in capital expenditures, consisting of $1.8 million related to the development of Western Catarina Midstream, and $0.5 million related to the development of oil and natural gas properties in the Palmetto Field in Gonzales County. These expenditures were funded with cash on hand and borrowings under our Credit Agreement.
- Hedging Activities. For the three months ended June 30, 2017, the non-cash mark-to-market gain for our commodity derivatives was approximately $1.3 million, compared to a loss of $13.2 million for the same period in 2016. For the six months ended June 30, 2017, the non-cash mark-to-market gain for our commodity derivatives was approximately $5.8 million, compared to a loss of $16.3 million for the same period in 2016.

Recent Developments

On August 9, 2017, the board of directors of our general partner declared a second quarter 2017 cash distribution on the Partnership's common units of $0.4441 per unit ($1.7764 per unit annualized) payable on August 31, 2017 to holders of record on August 22, 2017. The Partnership also declared a second quarter distribution on the Class B preferred units and elected to pay the distribution in cash. Accordingly, the Partnership declared a cash distribution of $0.28225 per Class B preferred unit payable on August 31, 2017 to holders of record on August 22, 2017.

On July 17, 2017, we closed the Oklahoma Production Divestiture pursuant to which we sold all of the Partnership's equity interests in the entities that owned our remaining operated Oklahoma production assets for cash consideration of $5.5 million. In addition, the buyer assumed all obligations relating to the assets arising after the effective date and all plugging and abandonment costs relating to the assets arising prior to the effective date. For the three months ended June 30, 2017, the net loss associated with the equity interests was approximately $0.7 million. After adding back approximately $0.7 million of depreciation, depletion and amortization plus approximately $0.1 million of accretion and $0.3 million of employee severance from the same quarter, the Adjusted EBITDA associated with these equity interests was approximately $0.4 million. For the six months ended June 30, 2017, the net loss associated with the equity interests was approximately $2.4 million. After adding back approximately $1.7 million of depreciation, depletion and amortization plus approximately $0.1 million of accretion and $0.3 million of employee severance from the same period, the Adjusted EBITDA associated with these equity interests was approximately $(0.3) million.

Results of Operations by Segment

Three months ended June 30, 2017 compared to three months ended June 30, 2016

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

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	For the Three Months Ended June 30,			
	2017	2016	Variance	
Revenues:				
Gathering and transportation sales	$ 14,176	$ 14,258	$ (82)	(1) %
Total gathering and transportation sales	14,176	14,258	(82)	(1) %
Operating expenses:				
Lease operating expenses	233	273	(40)	(15) %
Transportation operating expenses	3,032	3,014	18	1 %
General and administrative	1,461	1,428	33	2 %
Depreciation and amortization expense	6,013	5,094	919	18 %
Accretion expense	68	62	6	10 %
Total operating expenses	10,807	9,871	936	9 %
Operating income	$ 3,369	$ 4,387	$ (1,018)	(23) %

Gathering and transportation sales. We consummated the acquisition of Western Catarina Midstream from Sanchez Energy and entered into the related gathering and processing agreement with Sanchez Energy in October 2015. During the three months ended June 30, 2017, Sanchez Energy transported average daily production through the gathering system of approximately 11.5 MBbls/d of crude oil, 169.6 MMcf/d of natural gas and 16.9 MBbls/d of water. During the three months ended June 30, 2016, Sanchez Energy transported average daily production through the gathering system of approximately 14.1 MBbls/d of crude oil, 193.3 MMcf/d of natural gas and an insignificant amount of water. The decrease in throughput was driven by a decrease in Sanchez Energy's Catarina production of 562 MBoe over the three months ended June 30, 2017 compared to the same period in 2016.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, decreased $0.1 million, to $0.2 million for the three months ended June 30, 2017, compared to $0.3 million during the same period in 2016 which was entirely driven by an increase in the net taxable value of the midstream assets.

Transportation operating expenses. Our operating expenses generally consist of equipment rentals, chemicals, treating, metering fees, permit and regulatory fees, labor, minor maintenance, tools, supplies, and integrity management expenses. Our transportation operating expense remained flat for the three months ended June 30, 2017 and 2016 at $3.0 million.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by the Manager in connection with the Services Agreement and other costs not directly associated with field operations. Our general and administrative expenses totaled $1.5 million and $1.4 million for the three months ended June 30, 2017 and 2016, respectively. The increase resulted from a higher asset management fee due to a higher valuation for the gathering and transportation assets over the comparative periods.

Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense for the three months ended June 30, 2017 and 2016 was $6.0 million and $5.1 million, respectively. The increase was a result of revised useful lives used to depreciate the Western Catarina Midstream engines.

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Production Operating Results

The following tables sets forth the selected financial and operating data for the periods indicated (dollars and net production in thousands, except for average sales and costs):

	For the Three Months Ended June 30, 2017	2016	Variance	
Revenues:				
Natural gas sales at market price	$ 2,130	$ 2,398	$ (268)	(11) %
Natural gas hedge settlements	651	2,287	(1,636)	(72) %
Natural gas mark-to-market activities	(486)	(3,753)	3,267	87 %
Natural gas total	2,295	932	1,363	146 %
Oil sales at market price	5,061	3,505	1,556	44 %
Oil hedge settlements	1,215	3,196	(1,981)	(62) %
Oil mark-to-market activities	1,833	(9,457)	11,290	119 %
Oil total	8,109	(2,756)	10,865	394 %
Natural gas liquids sales	492	244	248	102 %
Miscellaneous expense	(43)	(332)	289	87 %
Total revenues	10,853	(1,912)	12,765	668 %
Operating expenses:				
Lease operating expenses	3,648	3,905	(257)	(7) %
Cost of sales	40	63	(23)	(37) %
Production taxes	353	326	27	8 %
General and administrative	4,892	3,550	1,342	38 %
Unit-based compensation expense	780	1,091	(311)	(29) %
Depreciation, depletion and amortization	2,924	1,035	1,889	183 %
Accretion expense	172	253	(81)	(32) %
Total operating expenses	12,809	10,223	2,586	25 %
Operating loss	$ (1,956)	$ (12,135)	$ 10,179	(84) %

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	For the Three Months Ended June 30,			
	2017	2016	Variance	
Net production:				
Natural gas production (MMcf)	925	1,209	(284)	(23) %
Oil production (MBbl)	110	82	28	34 %
Natural gas liquids production (MBbl)	26	20	6	30 %
Total production (MBOE)	290	304	(14)	(5) %
Average daily production (BOE/d)	3,187	3,335	(148)	(4) %
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.01	$ 3.88	$ (0.87)	(22) %
Natural gas price per Mcf without hedge settlements	$ 2.30	$ 1.98	$ 0.32	16 %
Oil price per Bbl with hedge settlements	$ 57.05	$ 81.72	$ (24.67)	(30) %
Oil price per Bbl without hedge settlements	$ 46.01	$ 42.74	$ 3.27	8 %
Liquid price per Bbl without hedge settlements	$ 18.92	$ 12.20	$ 6.72	55 %
Total price per BOE with hedge settlements	$ 32.93	$ 38.32	$ (5.39)	(14) %
Total price per BOE without hedge settlements	$ 26.49	$ 20.25	$ 6.24	31 %
Average unit costs per BOE:				
Field operating expenses(a)	$ 13.80	$ 13.94	$ (0.14)	(1) %
Lease operating expenses	$ 12.58	$ 12.87	$ (0.29)	(2) %
Production taxes	$ 1.22	$ 1.07	$ 0.15	14 %
General and administrative expenses	$ 19.56	$ 15.29	$ 4.27	28 %
General and administrative expenses without unit-based compensation	$ 16.87	$ 11.70	$ 5.17	44 %
Depreciation, depletion and amortization	$ 10.08	$ 3.41	$ 6.67	196 %

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Production. For the three months ended June 30, 2017, 38% of our production was oil, 9% was NGLs and 53% was natural gas as compared to the three months ended June 30, 2016, where 27% of our production was oil, 6% was NGLs and 67% was natural gas. The production mix between the periods has remained fairly consistent; however, we expect natural gas production to decrease as a percentage of total production due to the sale of our equity interests in the entities that owned our remaining Oklahoma production assets in a transaction that closed July 17, 2017. Additional production declines are anticipated due to the expected sale of non-operated production assets located in Texas. Combined production has decreased by 14 MBoe for the three months ended June 30, 2017, primarily due the sale of substantially all of our operated production assets in Oklahoma and Kansas (other than those arising under or related to a concession agreement with the Osage Nation) (the "Mid-Continent Divestiture"), and partially offset by the Production Acquisition.

Oil, NGL and natural gas sales. Unhedged oil sales increased $1.6 million, or 44%, to $5.1 million for the three months ended June 30, 2017, compared to $3.5 million for the same period in 2016. NGL sales increased $0.3 million, or 102%, to $0.5 million for the three months ended June 30, 2017, compared to $0.2 million for the same period in 2016. Unhedged natural gas sales decreased $0.3 million, or 11%, to $2.1 million for the three months ended June 30, 2017, compared to $2.4 million for the same period in 2016. Total increase in oil, NGL and natural gas sales for the three months ended June 30, 2017 was primarily the result of increased production from the Production Acquisition and higher market prices, partially offset by our Mid-Continent Divestiture.

Including hedges and mark-to-market activities, our total revenue increased $12.8 million for the three months ended June 30, 2017, compared to the same period in 2016. This increase was primarily the result of a $14.5 million increase in gains on mark-to-market activities plus a $1.6 million increase in oil sales, partially offset by a $3.6 million decrease in settlements on oil and natural gas derivatives.

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The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the three months ended June 30, 2017 to the three months ended June 30, 2016 (dollars in thousands, except average sales price):

	Q2 2017 Production Volume	Q2 2016 Production Volume	Production Volume Difference	Q2 2016 Average Sales Price	Revenue Increase/(Decrease) due to Production
Natural gas (Mcf)	925	1,209	(284)	$ 1.98	$ (563)
Oil (MBbl)	110	82	28	$ 42.74	$ 1,196
Natural gas liquids (MBbl)	26	20	6	$ 12.20	$ 73
Total oil equivalent (Mboe)	290	304	(14)	$ 20.25	$ 706

	Q2 2017 Average Sales Price	Q2 2016 Average Sales Price	Average Sales Price Difference	Q2 2017 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (Mcf)	$ 2.30	$ 1.98	$ 0.32	925	$ 295
Oil (MBbl)	$ 46.01	$ 42.74	$ 3.27	110	$ 360
Natural gas liquids (Mbl)	$ 18.92	$ 12.20	$ 6.72	26	$ 175
Total oil equivalent (Mboe)	$ 26.49	$ 20.25	$ 6.24	290	$ 830

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the three months ended June 30, 2017 by $0.8 million.

Hedging activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the three months ended June 30, 2017, the non-cash mark-to-market gain was $1.3 million, compared to a loss of $13.2 million for the same period in 2016. The 2017 non-cash gain resulted from lower future expected oil prices on these derivative transactions. Cash settlements received, including settlements receivable, for our commodity derivatives were $1.9 million for the three months ended June 30, 2017, compared to $5.5 million for the three months ended June 30, 2016.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses decreased $0.3 million, or 7%, to $3.6 million for the three months ended June 30, 2017, compared to $3.9 million during the same period in 2016. On a per unit basis, lease operating expenses were $12.58 per BOE, for the three months ended June 30, 2017, and $12.87 per BOE for the same period in 2016. The decreased lease operating expenses per BOE for the comparative periods were primarily the result of the divestiture of our Oklahoma assets.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by the Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit compensation expense, increased slightly to $5.7 million for the three months ended June 30, 2017, compared to $4.6 million for the same period in 2016. This increase was primarily driven by an increase in asset management fees of $0.7 million for the production segment and a $0.3 million increase in professional fees related to the sale of non-core production assets.

Our general and administrative expenses were $19.56 per BOE for the three months ended June 30, 2017, compared to $15.29 per BOE for the same period in 2016. Excluding unit-based compensation, our general and administrative costs were $16.87 per BOE for the three months ended June 30, 2017, compared to $11.70 per BOE for the same period in 2016. This increase resulted from decreased production noted above, which had an insignificant impact on our general and administrative expenses, as well as an increase in asset management and professional fees as noted above.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

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Our depreciation, depletion and amortization expense for the three months ended June 30, 2017 was $2.9 million, or $10.08 per BOE, compared to $1.0 million, or $3.41 per BOE, for the same period in 2016. This increase in the per BOE expense is primarily the result of the Mid-Continent Divestiture and a reduction in proved reserves due to changes in our development plans. Our non-oil and natural gas properties are depreciated using the straight-line basis.

Impairment expense. For the three months ended June 30, 2017 and 2016, we recorded no impairment charges.

Six months ended June 30, 2017 compared to six months ended June 30, 2016

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

	For the Six Months Ended June 30,			
	2017	2016	Variance	
Revenues:				
Gathering and transportation sales	$ 25,387	$ 28,133	$ (2,746)	(10) %
Total gathering and transportation sales	25,387	28,133	(2,746)	(10) %
Operating expenses:				
Lease operating expenses	492	371	121	33 %
Transportation operating expenses	6,328	6,068	260	4 %
General and administrative	2,966	2,713	253	9 %
Depreciation and amortization expense	14,913	10,168	4,745	47 %
Accretion expense	134	123	11	9 %
Total operating expenses	24,833	19,443	5,390	28 %
Operating income	$ 554	$ 8,690	$ (8,136)	(94) %

Gathering and transportation sales. We consummated the acquisition of Western Catarina Midstream from Sanchez Energy and entered into the related gathering and processing agreement with Sanchez Energy in October 2015. During the six months ended June 30, 2017, Sanchez Energy transported average daily production through the gathering system of approximately 11.4 MBbls/d of crude oil, 160.7 MMcf/d of natural gas and 8.5 MBbls/d of water. During the six months ended June 30, 2016, Sanchez Energy transported average daily production through the gathering system of approximately 14.0 MBbls/d of crude oil, 190.4 MMcf/d of natural gas and an insignificant amount of water. The decrease in throughput was driven by a decrease in Sanchez Energy's Catarina production of 1,481 MBoe over the six months ended June 30, 2017 compared to the same period in 2016.

Lease operating expense. Lease operating expenses, which includes ad valorem taxes, increased $0.1 million, to $0.5 million for the six months ended June 30, 2017, compared to $0.4 million during the same period in 2016. This increase was a result of a crank shaft failure at a central processing facility.

Transportation operating expenses. Our operating expenses generally consist of equipment rentals, chemicals, treating, metering fees, permit and regulatory fees, labor, minor maintenance, tools, supplies, and integrity management expenses. Our transportation operating expense for the six months ended June 30, 2017 and 2016 was $6.3 million and $6.1 million, respectively. The increase resulted from higher maintenance costs.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by the Manager in connection with the Services Agreement and other costs not directly associated with field operations. Our general and administrative expenses totaled $3.0 million and $2.7 million for the six months ended June 30, 2017 and 2016, respectively. The increase resulted from a higher asset management fee due to a higher valuation for the gathering and transportation assets over the comparative periods.

Depreciation and amortization expense Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, and up to 36 years for gathering facilities. Our depreciation and amortization expense for the six months ended June 30, 2017 and 2016 was $14.9 million and $10.2 million, respectively. The increase was a result of revised useful lives used to depreciate the Western Catarina Midstream engines.

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Production Operating Results

The following tables sets forth the selected financial and operating data for the periods indicated (dollars and net production in thousands, except for average sales and costs):

	For the Six Months Ended June 30, 2017	2016	Variance	
Revenues:				
Natural gas sales at market price	$ 4,406	$ 4,508	$ (102)	(2) %
Natural gas hedge settlements	1,297	4,526	(3,229)	(71) %
Natural gas mark-to-market activities	(572)	(4,694)	4,122	88 %
Natural gas total	5,131	4,340	791	18 %
Oil sales at market price	10,916	6,155	4,761	77 %
Oil hedge settlements	2,144	8,052	(5,908)	(73) %
Oil mark-to-market activities	6,399	(11,620)	18,019	155 %
Oil total	19,459	2,587	16,872	652 %
Natural gas liquid sales	959	520	439	84 %
Miscellaneous expense	(100)	(65)	(35)	(54) %
Total revenues	25,449	7,382	18,067	245 %
Operating expenses:				
Lease operating expenses	8,372	8,780	(408)	(5) %
Cost of sales	77	193	(116)	(60) %
Production taxes	826	547	279	51 %
General and administrative	8,996	7,984	1,012	13 %
Unit-based compensation expense	1,320	1,529	(209)	(14) %
Depreciation, depletion and amortization	6,205	3,149	3,056	97 %
Asset impairments	4,688	1,309	3,379	258 %
Accretion expense	364	507	(143)	(28) %
Total operating expenses	30,848	23,998	6,850	29 %
Operating loss	$ (5,399)	$ (16,616)	$ 11,217	(68) %

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	For the Six Months Ended June 30,			
	2017	2016	Variance	
Net production:				
Natural gas production (Mcf)	1,903	2,381	(478)	(20) %
Oil production (MBbl)	230	168	62	37 %
Natural gas liquids production (MBbl)	53	42	11	26 %
Total production (MBoe)	600	607	(7)	(1) %
Average daily production (Boe/d)	3,315	3,334	(19)	(1) %
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 3.00	$ 3.79	$ (0.79)	(21) %
Natural gas price per Mcf without hedge settlements	$ 2.32	$ 1.89	$ 0.43	23 %
Oil price per Bbl with hedge settlements	$ 56.78	$ 84.57	$ (27.79)	(33) %
Oil price per Bbl without hedge settlements	$ 47.46	$ 36.64	$ 10.82	30 %
Liquid price per Bbl without hedge settlements	$ 18.09	$ 12.38	$ 5.71	46 %
Total price per Boe with hedge settlements	$ 32.87	$ 39.16	$ (6.29)	(16) %
Total price per Boe without hedge settlements	$ 27.14	$ 18.43	$ 8.71	47 %
Average unit costs per Boe:				
Field operating expenses (a)	$ 15.33	$ 15.37	$ (0.04)	(0) %
Lease operating expenses	$ 13.95	$ 14.47	$ (0.51)	(4) %
Production taxes	$ 1.38	$ 0.90	$ 0.48	53 %
General and administrative expenses	$ 17.19	$ 15.68	$ 1.51	10 %
General and administrative expenses without unit-based compensation	$ 14.99	$ 13.16	$ 1.83	14 %
Depreciation, depletion and amortization	$ 10.34	$ 5.19	$ 5.15	99 %

(b) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Production. For the six months ended June 30, 2017, 38% of our production was oil, 9% was NGLs and 53% was natural gas as compared to the six months ended June 30, 2016, where 28% of our production was oil, 7% was NGLs and 65% was natural gas. The production mix between the periods has remained fairly consistent; however, we expect natural gas production to decrease as a percentage of total production due to the sale of our equity interests in the entities that owned our remaining operated Oklahoma production assets in a transaction that closed July 17, 2017. Additional production declines are expected due to the pending sale of certain non-operated production assets located in Texas. Combined production has decreased by 7 MBoe for the six months ended June 30, 2017, primarily due to the Mid-Continent Divestiture, partially offset by the Production Acquisition.

Oil, NGL and natural gas sales. Unhedged oil sales increased $4.8 million, or 77%, to $11.0 million for the six months ended June 30, 2017, compared to $6.2 million for the same period in 2016. NGL sales increased $0.4 million, or 84%, to $1.0 million for the six months ended June 30, 2017, compared to $0.5 million for the same period in 2016. Unhedged natural gas sales decreased $0.1 million, or 2%, to $4.4 million for the six months ended June 30, 2017, compared to $4.5 million for the same period in 2016. Total increase in oil, NGL and natural gas sales for the six months ended June 30, 2017 was primarily the result of increased production from the Production Acquisition and higher market prices, partially offset by our Mid-Continent Divestiture.

Including hedges and mark-to-market activities, our total revenue increased $18.1 million for the six months ended June 30, 2017, compared to the same period in 2016. This increase was primarily the result of a $22.1 million increase in gains on mark-to-market activities plus a $4.8 million increase in oil sales, partially offset by a $9.1 million decrease in settlements on oil and natural derivatives.

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The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our unhedged revenues from the six months ended June 30, 2017 to the six months ended June 30, 2016 (dollars in thousands, except average sales price):

	2017 Production Volume	2016 Production Volume	Production Volume Difference	2016 Average Sales Price	Revenue Increase due to Production
Natural gas (Mcf)	1,903	2,381	(478)	$ 1.89	$ (905)
Oil (MBbl)	230	168	62	$ 36.64	$ 2,272
Natural gas liquids (MBbl)	53	42	11	$ 12.38	$ 136
Total oil equivalent (Mboe)	600	607	(7)	$ 18.43	$ 1,503

	2017 Average Sales Price	2016 Average Sales Price	Average Sales Price Difference	2017 Volume	Revenue Increase/(Decrease) due to Price
Natural gas (Mcf)	$ 2.32	$ 1.89	$ 0.42	1,903	$ 803
Oil (MBbl)	$ 47.46	$ 36.64	$ 10.82	230	$ 2,489
Natural gas liquids (MBbl)	$ 18.09	$ 12.38	$ 5.71	53	$ 303
Total oil equivalent (Mboe)	$ 27.14	$ 18.43	$ 8.71	600	$ 3,595

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the six months ended June 30, 2017 by $1.7 million.

Hedging activities. We apply mark-to-market accounting to our derivative contracts and the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas sales. For the six months ended June 30, 2017, the non-cash mark-to-market gain was $5.8 million, compared to a loss of $16.3 million for the same period in 2016. The 2017 non-cash gain resulted from lower future expected oil prices on these derivative transactions. Cash settlements received, including settlements receivable, for our commodity derivatives were $3.4 million for the six months ended June 30, 2017, compared to $12.6 million for the six months ended June 30, 2016.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses decreased $0.4 million, or 5%, to $8.4 million for the six months ended June 30, 2017, compared to $8.8 million during the same period in 2016. On a per unit basis, lease operating expenses were $13.95 per BOE, for the six months ended June 30, 2017, and $14.47 per BOE for the same period in 2016. The decreased lease operating expenses per BOE for the comparative periods were primarily the result of our Mid-Continent divestiture.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, direct and indirect costs billed by the Manager in connection with the Services Agreement and other costs not directly associated with field operations. General and administrative expenses, inclusive of unit compensation expense, increased 8% to $10.3 million for the six months ended June 30, 2017, compared to $9.5 million for the same period in 2016. This increase was primarily driven by an increase in asset management fees of $1.2 million.

Our general and administrative expenses were $17.19 per BOE for the six months ended June 30, 2017, compared to $15.68 per BOE for the same period in 2016. Excluding unit-based compensation, our general and administrative costs were $14.99 per BOE for the six months ended June 30, 2017, compared to $13.16 per BOE for the same period in 2016. This increase resulted from increased asset management fees noted above.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as oil, NGL and natural gas production increases or decreases, our depletion expense would increase or decrease as well.

Our depreciation, depletion and amortization expense for the six months ended June 30, 2017 was $6.2 million, or $10.34 per BOE, compared to $3.1 million, or $5.19 per BOE, for the same period in 2016. The increase in the per BOE expense is primarily the result of the Mid-Continent Divestiture and a reduction in proved reserves due to changes in our development plans. Our non-oil and natural gas properties are depreciated using the straight-line basis.

Impairment expense. For the six months ended June 30, 2017, we recorded non-cash charges of $4.7 million, to impair certain of our producing oil and natural gas properties in Texas acquired as part of the Production Acquisition. During the same period in 2016, we recorded non-cash charges of $1.3 million to impair the value of our oil and natural gas fields located in Texas and Louisiana. The impairment expense recorded during the six months ended June 30, 2017 resulted from decreases in expectations for oil and natural gas prices in the future as well as changes to our expected future production estimates in certain areas.

Liquidity and Capital Resources

As of June 30, 2017, we had approximately $2.0 million in cash and cash equivalents and $22.0 million available for borrowing under the Credit Agreement in effect on such date. During the three months ended June 30, 2017, we paid approximately $1.9 million in cash for interest on borrowings under our Credit Agreement and approximately $40 thousand in cash for the commitment fee on undrawn commitments. For the six months ended June 30, 2017, we paid approximately $3.4 million in cash for interest on borrowings under our Credit Agreement and approximately $80 thousand in cash for the commitment fee on undrawn commitments.

Our capital expenditures during the three and six months ended June 30, 2017 were funded with cash on hand and borrowings under our Credit Agreement. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional limited partner units. We expect that the combination of these capital resources will be adequate to meet our short-term working capital requirements, long-term capital expenditures program and expected quarterly cash distributions.

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (the “Credit Agreement”). The Credit Agreement provides a maximum commitment of $500.0 million and has a maturity date of March 31, 2020. Borrowings under the Credit Agreement are secured by various mortgages of oil and natural gas properties that we own as well as various security and pledge agreements among the Partnership and certain of its subsidiaries and the administrative agent.

The amount available for borrowing at any one time under the Credit Agreement is limited to the borrowing base for our midstream assets and our oil and natural gas properties. Borrowings under the Credit Agreement are available for direct investment in oil and natural gas properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of $15.0 million, which may be used for the issuance of letters of credit. The initial borrowing base under the Credit Agreement was $200.0 million. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is equal to the rolling four quarter EBITDA of our midstream operations multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of our lenders. As of June 30, 2017, the borrowing base under the Credit Agreement was $215.6 million, with an elected commitment amount of $200.0 million.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank rate (“LIBOR”) plus an applicable margin between 2.25% and 3.25% per annum based on utilization or (ii) a domestic bank rate (“ABR”) plus an applicable margin between 1.25% and 2.25% per annum based on utilization plus

(iii) a commitment fee of 0.500% per annum based on the unutilized borrowing base. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

- Current assets to current liabilities for at least 1.0 to 1.0 at all times;
- Senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 4.5 to 1.0 if the adjusted EBITDA of our midstream operations equals or exceeds one-third of total

Adjusted EBITDA or 4.0 to 1.0 if the adjusted EBITDA of our midstream operations is less than one-third of total adjusted EBITDA; and

- minimum interest coverage ratio of at least 2.5 to 1.0 if the adjusted EBITDA of our midstream operations is greater than one-third of our total adjusted EBITDA.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

The Credit Agreement limits our ability to pay distributions to unitholders. We have the ability to pay distributions to unitholders from available cash, including cash from borrowings under the Credit Agreement, as long as no event of default exists and provided that no distributions to unitholders may be made if the borrowings outstanding, net of available cash, under the Credit Agreement exceed 90% of the borrowing base, after giving effect to the proposed distribution. Our available cash is reduced by any cash reserves established by the board of directors of our general partner for the proper conduct of our business and the payment of fees and expenses.

At June 30, 2017, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Sources of Debt and Equity Financing

As of June 30, 2017, the elected commitment amount under our Credit Agreement was set at $200.0 million and we had $178.0 million of debt outstanding under the facility, leaving us with $22.0 million in unused borrowing capacity. Our Credit Agreement matures on March 31, 2020.

Open Commodity Hedge Position

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices. These derivative contracts also limit our ability to have additional cash flows to fund higher severance taxes, which are usually based on market prices for oil and natural gas. Our operating cash flows are also impacted by the cost of oilfield services. In the event of inflation increasing service costs or administrative expenses, our hedging program will limit our ability to have increased operating cash flows to fund these higher costs. Increases in the market prices for oil and natural gas will also increase our need for working capital as our commodity hedging contracts cash settle prior to our receipt of cash from our sales of the related commodities to third parties. In 2016, we restructured a portion of our commodity derivative portfolio by liquidating “in-the-money” crude oil and natural gas derivatives settling in fourth quarter 2016 and using the proceeds from the sale liquidation to enhance the fixed price on natural gas derivatives to be settled in 2017. Cash settlement receipts of approximately $3.2 million from the termination of the crude oil and natural gas derivatives were applied as premiums for the enhanced natural gas derivatives in 2016.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. All of our derivatives are currently collateralized by the assets securing our Credit Agreement and therefore currently do not require the posting of cash collateral. This is significant since we are able to lock in sales prices on a substantial amount of our expected future production without posting cash collateral based on price changes prior to the hedges being cash settled.

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The following tables as of June 30, 2017, summarize, for the periods indicated, our hedges currently in place through December 31, 2020. All of these derivatives are accounted for as mark-to-market activities.

MTM Fixed Price Swaps— West Texas Intermediate (WTI)

	March 31,		June 30,		September 30,		December 31,		Total	
	Volume (Bbls)	Average Price	Volume (Bbls)	Average Price	Volume (Bbls)	Average Price	Volume (Bbls)	Average Price	Volume (Bbls)	Average Price
2017	—	$ —	—	$ —	87,304	$ 61.42	81,702	$ 61.55	169,006	$ 61.48
2018	88,854	$ 60.82	83,976	$ 60.90	79,683	$ 60.96	75,864	$ 61.02	328,377	$ 60.92
2019	78,667	$ 61.48	75,326	$ 61.53	72,279	$ 61.57	69,480	$ 61.61	295,752	$ 61.54
2020	66,914	$ 53.50	64,477	$ 53.50	62,251	$ 53.50	60,224	$ 53.50	253,866	$ 53.50
									1,047,001	

MTM Fixed Price Basis Swaps– NYMEX (Henry Hub)

	March 31,		June 30,		September 30,		December 31,		Total	
	Volume (MMBtu)	Average Price	Volume (MMBtu)	Average Price	Volume (MMBtu)	Average Price	Volume (MMBtu)	Average Price	Volume (MMBtu)	Average Price
2017	—	$ —	—	$ —	271,368	$ 5.45	257,234	$ 5.45	528,602	$ 5.45
2018	260,841	$ 3.18	248,018	$ 3.18	235,810	$ 3.18	225,208	$ 3.18	969,877	$ 3.18
2019	224,303	$ 3.10	214,186	$ 3.10	205,533	$ 3.10	197,455	$ 3.10	841,477	$ 3.10
2020	188,696	$ 2.85	176,946	$ 2.85	170,637	$ 2.85	164,747	$ 2.85	701,026	$ 2.85
									3,040,982	

Net Cash Provided by Operations

We had net cash flows provided by operating activities for the six months ended June 30, 2017 of $23.4 million, compared to net cash flow provided by operating activities of $17.3 million for the same period in 2016. This increase was primarily related to an increase in accounts payable and accrued liabilities of $7.3 million which was offset by a decrease in prepaid expenses of $0.6 million, a decrease in accounts receivable of $0.4 million and a decrease in accounts payable and accrued liabilities - related entities of $0.2 million.

Our operating cash flows are subject to many variables, the most significant of which is the volume of oil and natural gas transported through our Western Catarina midstream assets, volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future operating cash flows will depend on oil and natural gas transported through our Western Catarina midstream assets, our ability to maintain and increase production through our development program or completing acquisitions, as well as the market prices of oil and natural gas and our hedging program.

Net Cash Used in Investing Activities

We had net cash flows used in investing activities for the six months ended June 30, 2017 of $22.3 million, consisting of $13.8 million related to pipeline construction and contributions to Carnero Processing and Carnero Gathering totaling $8.5 million.

We had net cash flows used in investing activities for the six months ended June 30, 2016 of $2.3 million, consisting of $1.8 million related to the development of midstream assets, and $0.5 related to the development of oil and natural gas properties in the Palmetto Field in Gonzales County.

Net Cash Used in Financing Activities

Net cash flows used in financing activities was $0.1 million for the six months ended June 30, 2017. During the six months ended June 30, 2017, we had borrowings under our Credit Agreement of $25.0 million. We distributed $14.0 million and $12.0 million to Class B preferred unit holders and common unit holders, respectively, during the same period. Additionally, we paid $0.3 million in offering costs and received $1.3 million in proceeds from issuance of common units.

Net cash flows used in financing activities was $20.4 million for the six months ended June 30, 2016. During the six months ended June 30, 2016, we had borrowings under our Credit Agreement of $2.0 million. We distributed $16.2 million and $3.0 million to Class B preferred unit holders and common unit holders, respectively, during the same period. As part of our unit repurchase program, we used $2.9 million to repurchase and cancel 242,500 common units. Additionally, we paid $0.1 million in offering costs and $0.1 million related to units tendered by employees for tax withholding.

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In April 2017, we issued 84,577 common units in registered offerings for gross proceeds of approximately $1.3 million pursuant to a shelf registration statement originally filed with the SEC on March 6, 2015 as updated by that certain prospectus supplement filed with the SEC on April 6, 2017 (the "Shelf Registration Statement"). The Shelf Registration Statement allows the Partnership to sell up to $50.0 million of common units to fund general limited partnership purposes, including possible acquisitions. Net proceeds of $1.3 million from the equity issuance were used for general limited partnership purposes.

Off-Balance Sheet Arrangements

As of June 30, 2017, we had no off-balance sheet arrangements with third parties, and we maintained no debt obligations that contained provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the sale of oil and natural gas and our use of derivatives. Through June 30, 2017, we have not suffered any significant losses with our counterparties as a result of non-performance.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

As of June 30, 2017, there were no changes with regard to the critical accounting policies disclosed in our Annual Report on Form 10-K for the year ended December 31, 2016, which was filed with the SEC on March 28, 2017. The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read Part 1. Item 1. Note 2. "Basis of Presentation and Summary of Significant Accounting Policies" to the condensed consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

See Part 1. Item 1. Note 2. "Basis of Presentation and Summary of Significant Accounting Policies" to our condensed consolidated financial statements included in this report for information on new accounting pronouncements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are not required to provide this disclosure as a smaller reporting company.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Principal Executive Officer and the Principal Financial Officer of the general partner of SNMP have evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of June 30, 2017 (the Evaluation Date). Based on such evaluation, the Principal Executive Officer and the Principal Financial Officer have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and is accumulated and communicated to our management, including the Principal Executive Officer and the Principal Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

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Changes in Internal Control over Financial Reporting

During the three months ended June 30, 2017, there were no changes in SNMP's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, SNMP's internal control over financial reporting.

Part II—Other Information

Item 1. Legal Proceedings

From time to time we may be the subject of lawsuits and claims arising in the ordinary course of business. Management cannot predict the ultimate outcome of such lawsuits or claims. Management does not currently expect the outcome of any of the known claims or proceedings to individually or in the aggregate have a material adverse effect on our results of operations or financial condition.

Item 1A. Risk Factors

Consider carefully the risk factors under the caption "Risk Factors" under Part I, Item 1A in our 2016 Annual Report on Form 10-K, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2016 Annual Report; and in our other public filings, press releases, and public discussions with our management. Additional risks and uncertainties not currently known to us or that we currently deem immaterial may materially adversely affect our business, financial condition or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

In connection with providing services under the Services Agreement for the first quarter 2017, the Partnership issued 139,110 common units to SP Holdings, LLC on June 30, 2017. See Note 12, "Related Party Transactions" for additional information related to the Services Agreement. The issuance of these common units was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof as a transaction by an issuer not involving a public offering.

The Partnership elected to pay the first quarter 2017 distribution on the Class B preferred units in part cash and, with the consent of the Class B preferred unitholder, in part common units (in lieu of additional Class B preferred units). Accordingly, the Partnership issued 184,697 common units on May 22, 2017. The issuance of these common units was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof as a transaction by an issuer not involving a public offering. These units were registered on June 21, 2017.

No common units were purchased in the second quarter 2017.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the exhibit index accompanying this form 10-Q and are incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, Sanchez Midstream Partners LP, the Registrant, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SANCHEZ MIDSTREAM PARTNERS LP

(REGISTRANT)

BY: Sanchez Midstream Partners GP LLC, its general partner

Date: August 14, 2017 By /s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer and Secretary

(Duly Authorized Officer and Principal Financial Officer)

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EXHIBIT INDEX

Exhibit Number	Description
2.1*	Membership Interest Purchase and Sale Agreement between Sanchez Midstream Partners LP (f/k/a/ Sanchez Production Partners LP) and Exponent Energy, LLC dated May 10, 2017.
2.2*	Purchase and Sale Agreement between SEP Holdings IV, LLC and Sendero Petroleum, LLC dated June 30, 2017.
2.3*	Amendment No. 1 to Purchase and Sale Agreement between SEP Holdings IV, LLC and Sendero Petroleum, LLC dated July 31, 2017.
10.1*	Amendment No. 1 to Firm Gathering and Processing Agreement by and between SN Catarina, LLC and Catarina Midstream, LLC, dated June 30, 2017.
31.1*	Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Principal Executive Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Principal Financial Officer of Sanchez Midstream Partners GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

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* Filed herewith.

**Furnished herewith.